EXHIBIT 26

Part 4. Examining Process

Chapter 41. Oil and Gas Industry

Section 1. Oil and Gas Handbook (Cont. 4)

4.41.1 Oil and Gas Handbook (Cont. 4)

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4.41.1.6
Petroleum Refining

4.41.1.6.6
Direct Costs and Purchases — Domestic Crude

4.41.1.6.6.1
Foreign Crude

4.41.1.6.6.1.3
Exchanges

4.41.1.6.6.1.3.1 (07-31-2002)
Accounting For Exchanges

1. There are generally three methods used within the industry to account for exchanges as follows:

A. **Exchange Inventory Method.** Net balances due to or from exchange partners are merely added or subtracted from inventory balances with no gain or loss being realized until the ultimate sale.

B. **Gross Purchases and Sales Method.** Each exchange receipt is treated as a purchase and each exchange delivery as a sale.

C. **Net Purchases and Sales Method.** Using quantity accounting for exchange balances, end of period adjustments are made whereby favorable balances are recorded as accounts receivable and sales while unfavorable balances are recorded as purchases and accounts payable. Although this method does not recognize the limitation in IRC 1031 concerning nonapplicability to inventoriable goods, it is prevalent in the industry.

4.41.1.6.6.1.3.2 (02-19-2008)
Examining Exchange Transactions

1. The following may be helpful in determining proper treatment of like kind exchanges under IRC 1031:

   A. Ask the taxpayer to identify all material exchanges of property.

   B. Review the depreciation schedules for reductions in different classes of assets.

   C. On corporation returns, Schedule M should be considered for income not reported for tax purposes.

   D. Annual reports may footnote exchanges of property.

   E. Scan the property ledger.

   F. Ascertain the treatment of boot received by the taxpayer since boot may have been treated as a reduction in the basis of the asset received.

2. When examining inventoriable goods not subject to nonrecognition under IRC 1031, consider the following:

   A. Ascertain the accounting treatment used by the taxpayer in accounting for exchanges and treatment of any boot received.

   B. Ascertain if the taxpayer has consistently followed the method currently being used.

   C. Review year-end exchanges to identify possible exchange contracts entered into to protect LIFO inventory layers. An exchange contract entered into at year-end to protect a LIFO layer would normally involve a reversal after year-end. The potential for abuse is greater in those instances where one exchange partner uses the exchange inventory method and the other exchange partner uses the gross purchases and sales method. In this instance, both taxpayers can, under their method of accounting for exchanges, include the same goods in physical inventory.

   D. For those taxpayers using the exchange inventory method, see Treas. Reg. 1.481–1 prior to proposing a change in method of accounting.

   E. Make sure that favorable exchange balances (inventory items owed by the taxpayer) are treated the same as unfavorable balances (inventory items owed to others).

   F. Taxpayers using the exchange inventory method can experience instances when quantities deliverable under exchange contracts exceed actual inventory amounts. This can have a material impact depending upon the LIFO pools used by the taxpayer since the LIFO inventory must be adjusted for the "negative" inventory.

   G. Ascertain if periodic adjustments have been made to adjust exchange balance accounts through sales or purchases. Periodic adjustments is a suggested accounting treatment in COPAS Bulletin No. 17, section 10 entitled, Crude Oil Trading. However, this treatment is improper for tax purposes (see PLR 8043017).

4.41.1.6.6.2 (07-31-2002)
Utilities

1. Most large refineries distribute utility costs in their internal cost accounting systems. Their controls may involve a distribution to the various processing units as well as between utilities (fuel for steam generation). Many of the smaller refineries do not distribute or allocate utility expenses, and they control their utility operations through operational reviews and budgetary analysis.

   A. With ever-increasing costs for utilities, economic operations dictate the effective and efficient use of utilities. In many locations where utility costs are allocated, the initial distribution of utility costs is based on metered volumes. In some instances, a refiner may use meters, estimates, engineering standards, or a combination of the three methods.

   B. Electricity is normally purchased from a public utility company with some standby electrical generating capacity for emergency purposes.

   C. Natural gas may be purchased for intermediate use.

   D. Refinery operations require considerable amounts of steam, and steam generating units are to be anticipated. Frequently, where refinery or petrochemical operations are contiguous, the steam generating unit in one plant will supply steam to all plants involved. With single ownership of all plants, there are no apparent tax consequences. With separate/variable ownership of the plants, a sale of steam may be involved. The contractual agreements and the allocated costs for steam should be reviewed under appropriate circumstances.

4.41.1.6.6.3 (07-31-2002)
Filter Materials

1. Filtering materials are used in the production of petroleum products to remove impurities. The agent should verify that unconsumed filtering materials are inventoried at yearend. Refer to *IRM 4.41.1.6.6.1.1*, Finished Products, concerning the treatment of this item in inventory.

4.41.1.6.6.4 (07-31-2002)
Labor and Employee Benefits

1. Among the other direct costs to be attributed to the finished product, as throughput of the refinery, are the labor and applicable benefits of the employees directly related to the manufacturing operations of the refining industry. The entity being examined will normally maintain cost accounting records that accumulate all factors of costs that are component cost factors of the finished product. The agent should obtain these workpapers for use in examination and verification of all included direct cost factors of the finished product.

4.41.1.6.7 (12-03-2013)
Indirect Expenses — Depreciation and/or Amortization

1. Since depreciation is a major area of expense, the examiner should be alert to review the appropriateness of the deduction in conjunction with the engineer.
2. Certain incentives impact the depreciation computation and/or provide tax credits. See *IRM 4.41.1.6.7.6*.

4.41.1.6.7.1 (12-03-2013)
Modified Accelerated Cost Recovery System (MACRS) Problem Areas

1. Taxpayers may not use the applicable percentage stated in IRC 168(b) for recovery property used predominantly outside the United States. The determination that a property is used predominantly outside the United States is made by following the rules provided in Treas. Reg. 1.48-1(g).
2. Are the classes of property correctly designated, including recovery property used predominantly outside the United States?
3. Is the applicable percentage for the recovery deduction consistent with the alternative depreciation system?
4. Refiners should use Asset Class 13.3, Petroleum Refining, for depreciation purposes. Class 13.3 has a GDS recovery period of 10 years and a class life of 16 years. An issue exists where some refiners may propose to change their method of depreciation for certain assets used in petroleum refineries to Asset Class 28.0, Manufacture of Chemicals and Allied Products. Class 28.0 has a GDS recovery period of 5 years and a class life of 9.5 years. This issue could also exist for the misclassification of new asset additions. A Field Directive on this issue was issued April 2, 2002. The Directive recommends the following 2 positions:
   - all processing assets involved in the activity of petroleum refining are to be included in MACRS Asset Class 13.3. This would include any incidental manufacturing or waste removal processes, which are integral parts of petroleum refining.
   - Where the taxpayer is engaged in more than one industrial activity, the activity of each asset's primary use should be used for classification.
5. Alternative Depreciation System (ADS) must be used for certain property (refer to IRC 168(g). ADS generally requires using the straight line method, the applicable convention under IRC 168(d) and a recovery period based on the class life of an asset. Examiners should look for two types of refinery assets:
   A. Any tangible property which during the taxable year is used predominantly outside the United States. Foreign real property is ADS with a recovery period of 40 year.
   B. Any tax-exempt bond financed property. Examiners have found that refiners occasionally receive tax-exempt financing for construction of equipment to process low-grade fuel supplies but fail to use the ADS method.

4.41.1.6.7.1.1 (07-31-2002)
Patents

1. The petroleum refining and petrochemical processes involve the use of, and the development of, high technology involving patents and patent rights. The taxpayer may obtain rights to a patent by paying a royalty fee, by purchase, or by obtaining a patent for processes developed in-house.
2. Royalty payments usually extend over the remaining life of the patent rights obtained. Payments over a period substantially shorter than the life of the patent rights obtained may indicate that a lease purchase agreement is involved. A patent or a patent right is an intangible asset. Accelerated methods of depreciation generally may not be used for patents. See Treas. Reg. 1.167(a)-14(c)(4).
3. Generally, the purchase price and the related costs of acquiring the patent are depreciable over the remaining life of the patent (Treas. Reg. 1.167(a)–6), or a shorter period, if it can be estimated with reasonable accuracy, Treas. Reg. 1.167(a)–3. The straight line method of depreciation is normally used. Other methods not expressed in term of years may be utilized when appropriate. See Treas. Reg. 1.167(a)-14(c)(4).
4. The in-house development of patent rights may include research and experimental expenditures deductible under the provisions of IRC 174. The cost basis of a patent subject to depreciation includes not only the purchase price but the costs of government fees, drawings and models, materials and labor allocated to perfecting it, attorney fees and the cost of clearing the legal title, Treas. Reg. 1.167(a)–(6)(a).
5. If the patent becomes valueless in any year before its expiration, the unrecovered cost may be deducted in that year, Treas. Reg. 1.167(a)–6(a).
6. Areas of interest in the examination of patents and patent rights include:
   A. The review of the taxpayer's beginning of the year and end of the year record of patents and patent rights.
   B. Has taxpayer properly capitalized the costs of the patents?
   C. Does taxpayer claim excessive depreciation?
   D. Does taxpayer pay excessive royalties or fees to a controlled foreign corporation or related party that may require the application of the provisions of IRC 482?
   E. Does taxpayer sell patents in the ordinary course of business? The sale or exchange of patents is discussed in *IRM 4.41.1.6.5.3*.
   F. Has taxpayer transferred a patent to a controlled foreign corporation or other related party which may be reported as long term gain in error?

4.41.1.6.7.1.2 (12-03-2013)
Catalysts

1. The various types of catalysts used in the petroleum refining and petrochemical processes include some with a nominal cost and some that are extremely valuable. An overview of the accounting treatment, the identity of, the status of, and the use of catalysts in the refinery processes is included in *IRM 4.41.1.6.1.4* and *IRM 4.41.1.6.8.2*.
2. In most instances, the metal in the catalyst is not consumed, does not lose its identity, and very little, if any, is lost in the refining process. It is not subject to wear and tear, to decay, to exhaustion, or obsolescence. As such, it is not of a character subject to the allowance for depreciation under IRC 167 and IRC 168.
3. Precious metals in the catalyst that are lost in the refining process or otherwise unrecoverable for reuse is property subject to wear and tear, exhaustion, or obsolescence. Thus, it is of a character subject to the allowance for depreciation under IRC 167 and IRC 168. These costs, in addition to the "other capitalized costs" constitute the "depreciable basis" of the catalyst. "Other" includes such items as the frame, screen, bedding, freight-in, commissions and fees related to the acquisition, and related costs to bring the catalyst to that point in time when it is ready to be placed in service.
4. Following are some of the factors for examination:
   A. The Schedule M *(Reconciliation of Income Per Books with Income Per Return)* amounts should be examined for any unusual deductions claimed on the return, but not deducted in the books, that may involve catalyst depreciation.
   B. The catalyst expense included in the return (identified in the tax workpapers, working trial balance, or other) should be compared to the monthly book amount for catalyst depreciation, royalties, rents, or any unusual expenses.

C. Taxpayer's internal controls for catalyst and the asset accounts for the inventory of catalysts should be reviewed together with the title records and agreements for royalties and rent expenses.

D. Tax workpapers for the analysis of the inventory of catalysts such as date acquired, whether owned or leased and the depreciation computation detail.

5. The problem areas for examination of depreciation deducted for catalysts include the following:

   A. The costs may be deducted in error.

   B. The acquisition costs and expenditures to bring the catalyst to that point in time when it is ready to be placed in service may be deducted in error.

   C. The cost of economically recoverable precious metals (and in some cases, the cost of nonprecious metals) may be included in depreciable basis in error.

   D. Determining the appropriate amount of previous metal that is ultimately recoverable for reuse vs. the amount that is not recoverable for reuse.

4.41.1.6.7.1.3 (02-19-2008)
Certified Pollution Control Facility

1. The taxpayer has an election to amortize over 60 months the basis of any ceritified pollution control facility; refer to IRC 169(f). See IRC 169(d)(5) for an exception of 84-month amortization period applicable to certain air pollution control facilities placed in service after April 11, 2005. It should be noted that the Federal certifying authority does not certify any property when it appears that its costs will be recovered over its actual useful life from profits derived through the waste recovery or otherwise in the operations of such property. The amortization deductions are subject to recapture to the extent of any gain on the sale of the facility; see IRC 1245(a)(3)(C).

4.41.1.6.7.2 (10-01-2005)
Overhead

1. Overhead items are those costs necessary for production which cannot be conveniently traced to a specific unit of finished product.
2. The cost accounting system groups all such individual items together or applies them to products through the use of some allocation method and base.
3. An improper choice of the method or base may distort income through an erroneous inventory valuation.
4. Examiners should carefully review overhead allocations to insure that the taxpayer is complying with the uniform capitalization rules of IRC 263A. Treas. Regs. 1.263A–1 through 1.263A-3 set forth the guidelines and should be reviewed.
5. Consideration also should be given to the impact of Treas. Reg. 1.861–8 on overhead allocations.
6. Commonly accepted accounting terminology to use in analyzing overhead is provided in *Exhibit 4.41.1-16*.
7. A good source of examination leads might be cost of production reports. An example of the contents of a cost of production report is shown in *Exhibit 4.41.1-20*.

4.41.1.6.7.3 (12-03-2013)
Repairs

1. Refinery repairs are normally very substantial due to the nature of refining processes. Examination focus on the most substantial amount items is recommended.
2. Refinery repair accounts normally have a large volume of activity. Due to this large volume, it is often an area well suited for the use of statistical sampling methods to detect misclassified items. Because of the technical nature of refinery assets, the assistance of an IRS engineer is beneficial.

4.41.1.6.7.4 (12-03-2013)
Turnarounds

1. The term "turnaround" in the context of refining refers to a period of time that the refinery is shut down to perform preventive maintenance. The agent should expect to see a large portion of the yearly repair expense incurred during this brief interval of time. Depending on the process unit impacted and the amount of maintenance or repair needed, the length of turnaround can range from one to four weeks or even longer.
2. During turnarounds, the taxpayer may be also making some capital improvements, i.e., changing out old equipment for new equipment, adding new units, etc. Even though the purpose of the turnaround is primarily to do preventive maintenance, capital expenditures may be incurred simultaneously.
3. When analyzing whether turnaround expenditures (or any repair expenses) are capital expenditures, examiners should apply the appropriate capitalization regulations and consider the applicability of the LB&I Stand Down Directive dated March 15, 2012. Specific attention should be given to whether a turnaround:
   - is an improvement to a unit of property per Treas. Reg. 1.263(a)-3T(d);
   - results in a betterment of a unit of property per Treas. Reg. 1.263(a)-3T(h); or
   - qualifies as a safe harbor for routine maintenance expenses under Treas. Reg. 1.263(a)-3T(g).
4. The regulations contain applicable examples and highlight potential audit areas to consider in examining turnaround expenditures. Example 9 in Treas. Reg. 1.263(a)-3T(g) "routine maintenance with betterments" illustrates that routine maintenance expenses would not qualify for the routine maintenance safe harbor if they were necessary to result in a betterment (such as, but not limited to, materially increasing capacity, productivity, efficiency, strength or quality). Example 10 "exceptions to routine maintenance" illustrates that expenses are not routine maintenance if they return a unit of property to its former ordinary efficient operating condition if the property has deteriorated to a state of disrepair and is no longer functional for its intended use.
5. When encountering capital expenditures, the agent should determine that all related costs have been properly included in the amount capitalized. This may include removal costs of old equipment or other modifications to the plant which are necessary in order to enable the new equipment to be installed and used. The agent should ascertain that labor and indirect costs associated with the capital item have been capitalized.

4.41.1.6.7.5 (07-31-2002)
Royalty and Licensing Fees

1. The task of successfully operating refineries and petrochemical plants necessitates the use of various royalty or licensing arrangements. During the examination, the agent should be alert to the payment of these fees. Such payments may be to related entities and if so, the contracts requiring their payment should be analyzed for arm's-length pricing. The contracted arrangements for the payment of these fees are usually related to units of throughput or units of production.

2. The payment of royalty or licensing fees become obvious and are more likely to occur when acquisition, construction, and/or expansion of plant facilities is undertaken. The agent should be alert to any advance payments of these fees that would be payable on future production as throughput in the manufacturing processes of the refining and petrochemical plants.

4.41.1.6.7.6 (12-03-2013)
Tax Incentives for Refining and Use of Renewable Fuels - IRC 179B, 45H, 179C and 40A

1. Beginning with tax year 2003 certain tax incentives for refining and use of renewable fuels were added to the IRC. These incentives include:
   - IRC 179B – Deduction for Capital Costs Incurred in Complying with Environmental Protection Agency Sulfur Regulations
   - IRC 45H – Credit for Production of Low Sulfur Diesel Fuel
   - IRC 179C – Election To Expense Certain Refineries
   - IRC 40A – Biodiesel and Renewable Diesel Credits - See *Exhibit 4.41.1-31* for a brief history.

4.41.1.6.7.6.1 (12-03-2013)
IRC 179B

1. Deduction for Capital Costs Incurred in Complying with Environmental Protection Agency Sulfur Regulations. This provision permits small business refiners to claim an immediate deduction for up to 75 percent of the qualified costs paid or incurred when complying with EPA's highway diesel fuel sulfur control requirements. IRC 179B was created by the American Jobs Creation Act of 2004.
2. A small business refiner is a taxpayer in the business of refining petroleum products who employs less than 1,500 employees and had less than 205,000 barrels per day (average) of total refining runs in 2002. Examiners should be aware that the 1,500-employee test is for any day in the taxable year. In contrast, the tests involving refining runs refer to the 1-year period ending on December 31, 2002.
3. Qualified costs are defined in IRC 45H. They include expenditures for the construction of new process units or the dismantling and reconstruction of existing process units to be used in the production of low sulfur diesel fuel, associated adjacent or offsite equipment (including tankage, catalyst, and power supply), engineering, construction period interest, and sitework.
4. The percentage of costs allowed is reduced for amounts in excess of 155,000 barrels a day of total refinery runs.
5. The provision is effective for expenses incurred after December 31, 2002. As a result, examiners will need to be alert for potential claims that may be filed for tax years ending after this date.

4.41.1.6.7.6.2 (12-03-2013)
IRC 45H

1. *Credit for Production of Low Sulfur Diesel Fuel*, IRC 45H. It provides a general business credit to small business refiners equal to 5-cents for each gallon of low-sulfur diesel fuel produced during the taxable year that complies with EPA sulfur control requirements. IRC 45H was created by the American Jobs Creation Act of 2004.
2. The total production credit claimed by the taxpayer cannot exceed 25 percent of the qualified cost incurred to comply with the EPA's highway diesel fuel sulfur control requirements.
3. Basis in the property is reduced by the amount of credit claimed.
4. To obtain the credit, the taxpayer will have to secure certification that the qualified costs will result in compliance with EPA regulations.
5. The provision is effective for expenses incurred after December 31, 2002 and ending on the earlier of the date that is one year after the date on which the taxpayer must comply with the applicable EPA regulations or December 31, 2009.

4.41.1.6.7.6.3 (12-03-2013)
IRC 179C

1. *Election To Expense Certain Refineries*, IRC 179C. Under present law, petroleum refining assets are depreciated over a 10-year recovery period using the double declining balance method. Section 179C provision provides a temporary election to expense 50 percent of the cost of qualified refinery property. Any cost so treated is allowed as a deduction for the taxable year in which the qualified refinery property is placed in service. The remaining 50 percent is recovered under present law. IRC 179C was created by Energy Policy Act of 2005.
2. Temporary regulation section 1.179C-1T was issued on July 3, 2008. Shortly thereafter the Energy Improvement and Extension Act of 2008 extended the provisions of section 179C by two years and also modified the provisions in sections 179C(d) and 179C(e)(2) dealing with shale and tar sands.
3. In general “qualified refinery property” means any portion of a qualified refinery that is located in the United States and which is used for the primary purpose of processing liquid fuel from crude oil or qualified fuels as defined in IRC 45K(c), or directly from shale or tar sands.
4. Specific rules regarding the property include:

Rule	Date Placed in Service
original use commences with taxpayer	after August 8, 2005 and before January 1, 2014
meets all applicable environmental laws in effect	placed-in-service date
increases the capacity of an existing refinery by at least 5 percent or which increases the percentage of total throughput attributable to qualified fuels such that it equals or exceeds 25 percent	not a factor
with respect to the construction of which there is a binding contract	in the case of self-constructed property, the construction of which began after June 14, 2005 and before January 1, 2010

5. The increased capacity requirements refer to the output capacity of the refinery, as measured by the volume of finished products other than asphalt and lube oil, rather than input capacity as measured by rated capacity. It would be determined as of the date the property is placed in service. Any reasonable method may be used to determine the baseline capacity and to demonstrate and substantiate the required increase in capacity.
6. The expensing election is not available with respect to identifiable refinery property built solely to comply with federally-mandated projects or consent decrees. For example, a taxpayer may not elect to expense the cost of a scrubber, even if the scrubber is installed as part of a larger project, if the scrubber does not increase throughput or increased capacity to accommodate qualified fuels and is necessary for the refinery to comply with the Clean Air Act. This exclusion applies regardless of whether the mandate or consent decree addresses environmental concerns with respect to the refinery itself or the refined fuels.
7. A taxpayer may not claim a deduction under section 179C for any taxable year unless it files a report as specified in the regulations with respect to the operation of the taxpayer's refineries. Generally the taxpayer would attach the report to its filed tax return in the year the property is placed in service.

8. Effective Date: The provision is effective for property placed in service after August 8, 2005, the original use of which begins with the taxpayer, provided the property was not subject to a binding contract for construction on or before June 14, 2005.

4.41.1.6.7.6.4 (12-03-2013)
IRC 40A

1. *Credit for Biodiesel and Renewable Diesel Used As Fuel*, IRC 40A. This section provides a $1.00 per-gallon credit (reportable as a General Business Tax Credit) relating to the following fuels: biodiesel, agri-biodiesel, renewable diesel, biodiesel included in a biodiesel mixture, agri-biodiesel included in a biodiesel mixture and renewable diesel included in a renewable diesel mixture. This is a complex area with many rules and limitations. Figure 4.41.1-1 defines some key terms. Consult an Energy Credit Technical Specialist if you need further guidance.

Figure 4.41.1-1

Terminology and Computation of Biodiesel and Renewable Diesel Fuel Credits

Term	Definition	Computation of Credit
Biodiesel	Monoalkyl esters of long chain fatty acids derived from plant or animal matter which meet the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act (42 U.S.C. 7545), and the requirements of the American Society of Testing and Materials D6751	$1.00 per gallon credit which during the year was used as a fuel in a trade or business, or sold at retail to another person and put in the fuel tank of that person's vehicle. No credit is allowed for fuel used in a trade or business that was purchased in a retail sale. A credit of $1.00 per gallon is only available by the producer or sold in a trade or business as a fuel to another person.
Renewable Diesel	Diesel fuel derived from biomass which meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act (42 U.S.C. 7545), and the requirements of the American Society of Testing and Materials D975 or D396, or other equivalent standard approved by the Secretary	Same as for Biodiesel Credit
Agri-biodiesel	Biodiesel derived solely from virgin oils, including esters derived from virgin vegetable oils from corn, soybeans, sunflower seeds, cottonseeds, canola, crambe, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds, and camelina, and from animal fats	$.10 per gallon credit for each gallon of qualified agri-biodiesel produced by any eligible small agri-biodiesel producer. To qualify for the credit, the agri-biodiesel must be sold by such producer to another person for a) use by such other person in the production of a qualified biodiesel mixture in such other person's trade or business (other than casual off-farm production); or b) use by such other person as a fuel in a trade or business. A qualifying producer may also sell such agri-biodiesel at retail to another person who then places it in the fuel tank of such other person. **Note:** Small producers have capacity less than 60,000,000 gallons. Eligible producers have a limit of 15,000,000 gallons.
Qualified mixture	Combines biodiesel or renewable diesel with diesel fuel determined without regard to any use of kerosene. Kerosene should be treated as diesel fuel when figuring a renewable diesel mixture credit for certain aviation fuel	

2. The Biodiesel and Renewable Diesel Fuels Credit is claimed by completing Form 8864. A certification form from the producer or reseller identifying the product produced and the percentage of biodiesel and agri-biodiesel in the product must be attached to the Form 8864.

3. **Limitations and Special Rules**. For pass-through entities, the 15,000,000 and 60,000,000 gallon limits are applied at both the entity level and at the partner or similar level. All members of the same controlled group of corporations (within the meaning of section 267(f)) and all persons under common control (within the meaning of section 52(b) but determined by treating an interest of more than 50 percent as a controlling interest) are treated as one person. The amount of the Biodiesel and Renewable Diesel Fuels Credit under IRC 40A is properly reduced to take into account any excise tax credit benefit provided with respect to such biodiesel. The Biodiesel and Renewable Diesel Fuels Credit is not applicable to any biodiesel which is produced outside the United States for use as a fuel outside the United States. Taxpayers are liable for excise tax on biodiesel and renewable diesel sold for use in a diesel-powered highway vehicle. The excise rate is 24.4 cents per gallon and is filed quarterly on Form 720, Quarterly Federal Excise Return.

4. **Examination Techniques**. Examiners should be aware that the Biodiesel and Renewable Diesel Fuels Credits are includible in gross income under IRC 87 and IRC 40A. If the Taxpayer filed a Form 8864 for the Biodiesel and Renewable Diesel Fuels Credit, a compliance check of the Taxpayer's Form 720, Quarterly Federal Excise Return, should be made to determine if there are duplications in claiming both the biodiesel credit and the excise tax credit. There are recapture provisions under IRC 40A(d)(3) if the biodiesel or biodiesel mixture is not used as fuel or if the biodiesel is separated from the biodiesel mixture. The Energy Credit or Agriculture Subject Matter Experts can be contacted for additional trends, examinations techniques and directives. The instructions for completing Form 8864 should be reviewed for additional limitations, definitions and revisions.

4.41.1.6.8 (07-31-2002)
Joint Operations

1. The petroleum industry has a long history of using joint operations as a vehicle for its activities. The basic premise involved in the examination of joint operations is the classification of the organization as a partnership, an association taxable as a corporation, or merely a tenants-in-common co-ownership.

2. A tenants-in-common arrangement usually involves the mere co-ownership of property that is maintained, kept in repair and rented, or leased with no operations involved. Such an arrangement is not considered a partnership, Treas. Reg. 301.7701–1(a)(2).

3. The participants in joint operations are pooling their resources, know-how, and services for the purpose of sharing the risk and the potential economic rewards. The operator of the refinery may be involved in several different joint operations.

4. The construction of plants for further manufacturing of refinery products frequently involves joint operations. The refinery products that constitute resource material for fertilizers, chemicals, plastics, etc., may be the subject of the joint construction of a plant and/or the joint operations of such a plant or facility. The instruments governing the joint operations provide authority for the construction and/or the management of the facility, the conduct of the operations, and the division of the profits and losses, or the delivery of the plant products.

5. Occasionally, the participants organizing the joint operations as tenants-in-common for sharing expenses, etc., find that, in fact, they meet the standards requiring the organization to be recognized as a partnership. Under certain circumstances the participants may qualify to be excluded from the provisions of Subchapter K of the Code regarding the requirement to file partnership returns. The most common organization formed in a joint operating arrangement is the partnership entity, IRC 7701(a)(2).

4.41.1.6.8.1 (07-31-2002)
Areas of Interest in Examination of Joint Operations

1. If a partnership return has been filed, the control of the returns of the participants should be inaugurated as early as possible in the examination process so the determination may be uniformly applied and the statute of limitations protected.

2. If a partnership return has not been filed, information reports should be disseminated as early as possible in the examination to ensure uniform application of the determination of a potential issue and to protect the statute of limitations.

3. Does the co-ownership arrangement constitute an "association" taxable as a corporation?

4. If the joint operations qualify as a "partnership," have the partners made an election to be excluded from the provisions of Subchapter K?

5. Do the partners jointly sell the "partnership," products which may negate the election to be excluded from Subchapter K?

6. Does the partnership have "startup" expenditures that should be capitalized?

7. Are the organization expenditures properly capitalized?

8. Do any of the partners have losses allocated to them in excess of their adjusted basis in the partnership per IRC sections 704(d) and 705?

9. Does the operator of the refinery engage in any activity described in IRC 465(c) subject to the at-risk rules in IRC 465?

4.41.1.6.8.2 (07-31-2002)
Types of Catalysts

1. As discussed in *IRM 4.41.1.6.1.4*, many substances are used as catalysts. The royalty or licensing agreement for use of a particular type processing unit may also include an agreement for use of the designer's catalyst or any subsequently developed catalyst for the unit. The catalyst may be purchased or rented from parties other than the designer/licenser of the processing unit. The refiner may design its own processing unit and manufacture its own catalyst or purchase/rent the catalyst on the open market.

2. It is not feasible to establish guidelines based on the type processing unit or on the content of the catalyst alone. Similar processing units will utilize different catalysts in different refineries. Sometimes the catalyst in a particular unit will be switched to a new improved variety. The catalyst for a particular process at one installation may involve precious metals while at another installation the precious metals are absent. One installation of a particular type process may use a liquid catalyst while another installation uses a solid catalyst with differences in operational factors. Analysis based on catalyst content alone is insufficient, as operational factors often are more indicative of proper accounting treatment.

3. As shown in *Exhibit 4.41.1-21*, the named processing units are indicative of the type of process involved. For each type process, there are different licensed processes available with variables in type of catalyst, type of reactor, method of regeneration (if applicable), method and timing of catalyst recharging, and other processes.

4. Particle size of solid catalyst varies by the type of operation. In fixed bed reactors, the catalyst stays put in a chamber (reactor), and the hydrocarbon flows through or is dribbled through the catalyst. An extended residence time is usually found where fixed bed reactors are involved. Frequently, there are several reactors, and a cyclic operation is involved. Where regeneration is involved, several reactors may be on stream (processing the hydrocarbons) while others are in a regeneration cycle (burning off the carbon) or in a recharging cycle. The size of the catalyst in fixed bed reactors is larger than in moveable bed reactors.

5. With moveable beds, both the hydrocarbon and the solid catalyst flow through the reaction chamber. In catalytic cracking, after a very short residence time, the mixture is separated with the catalyst circulated to the regeneration chamber. The type catalyst is generally bead or particle.

   A. The beads are approximately $^1/_8$ to $^1/_4$ inch in diameter and extremely porous to provide extensive reaction surface area. The small size permits movement through the chambers. Beads are not now as acceptable, as particles are more effective.

   B. The particles are much smaller and have the appearance of fine sugar or baby powder. The particle type (it also is very porous) is now more prevalent due to its fluidity. If the particles are placed in a container and the container is tilted or shaken, they react just like a fluid (liquid). The nomenclature, fluid catalytic cracker, is with reference to particle type catalysts. This type cracker utilizes the enhanced fluidity/mobility for internal movement of the catalyst through the reactor, regenerator, or other component.

6. One example of the use of liquid catalysts is in alkylation units where the catalyst is usually sulfuric acid or hydrofluoric acid. The mixture of hydrocarbons and acid is pumped through a battery of chilled reactors to provide an extended residence time. The mixture then moves to a vessel (acid settler) where no mixing takes place, and the acid and hydrocarbons separate like oil and water. As the acid circulates through the process, it gets diluted with water and picks up tar. As the acid concentration declines, it is partially drawn off, and it may be sent back to the acid supplier for refortification (purification). Internal regeneration of the catalyst is not found in this type process. The partial withdrawal of a diluted catalyst, with additions of a fresh catalyst, is an ongoing operation. It should be noted that some alkylation units utilize a solid catalyst, rather than a liquid catalyst.

7. The reclamation costs for some catalysts may be so great, in relation to the original purchase price, that they are dumped when their effectiveness declines. Some catalysts may be used up in the manufacturing process in one way or another, even though they do not enter into the reaction itself.

8. The use of catalysts is also involved in petrochemical operations. The production of ammonia (NH3) provides an example of the extensive use of catalysts in the petrochemical field. As seen in the above formula, ammonia contains one part nitrogen and three parts hydrogen. In many installations, the source of the nitrogen is air, and the source of the hydrogen is methane gas. The liquefaction and separation of nitrogen from air do not involve a catalyst. A mixture of methane and steam flow through furnace tubes packed with a catalyst to produce a stream of hydrogen, carbon dioxide, steam, and carbon monoxide. This stream then flows through a vessel packed with a catalyst for shift conversion of the carbon monoxide to carbon dioxide (with the generation of additional hydrogen). The produced hydrogen is separated and proportionately mixed with the nitrogen for conversion to ammonia. Such conversion requires high pressure and a catalyst. If the subsequent production of nitric acid is involved, a catalyst is also involved.

4.41.1.6.8.2.1 (07-31-2002)
Accounting Treatment

1. There are often tax accounting inconsistencies in proper capitalization, depreciation, or treatment when catalysts are involved. The internal accounting instructions and procedures for catalysts (for unit cost accounting or financial accounting) of different companies vary. However, an understanding of general internal accounting procedures may be helpful in clarifying the treatment of catalyst costs. An understanding of a particular taxpayer's internal accounting procedures is essential in the agent's examination of the taxpayer.

2. In most cases, a company will have specific procedures when catalysts with precious metals are involved. This is due to the significant costs involved and the arrangements for reclamation with credit for the precious metal(s). A single processing unit may require several million dollars worth of such catalysts.

   A. The precious metal content alone may comprise 50–65 percent of the total cost of such catalysts. The balance of the total cost would be the manufacturer's production fee, freight, and sometimes a royalty fee.

   B. When the catalyst is purchased, the total cost may be charged to a prepaid inventory account. Later, when the catalyst is issued to the process unit, a cost may be capitalized and amortized for internal unit cost accounting purposes or deducted as a current expense. The amortized cost may be the total cost, or it may be a net cost (total cost, less original metal cost or less salvage value of the metal and projected reclamation costs).

   C. Some companies may maintain the original charge is inventory on an indefinite basis and expense/amortize only the replacement quantities.

   D. It should be noted that some refiners may own excess quantities of the precious metal itself or of such catalysts, and they are sometimes rented to other companies.

3. While those metallic base catalysts without precious metals are less costly, in many instances the cost is still substantial. As such, with reclamation and credits for spent catalysts, the nonprecious base metal(s) may require the same treatment as precious metal(s).

4. Beyond special procedures for precious metals, some companies will (for unit cost accounting purposes) segregate catalysts based on operational differences: those that are used in quantity each month or those that are used in quantity every 12–24 months or a further extended period.

   A. Monthly utilization (make-up) might be found at some cracking units or alkylation units. Some of the catalyst is regularly partially withdrawn and is either reclaimed, sold at its salvage value, or junked. The original charge of such catalysts is normally capitalized to the cost of the processing unit and amortized (for unit cost purposes) over the useful life of the unit. The reason for such treatment is that there always is an equivalent amount of catalyst in the unit. The net cost of a fresh catalyst added (make-up) is normally expensed. Some refiners may expense the original charge for unit cost purposes.

   B. Extended utilization, without significant make-up between recharges, might be found at a reformer where the catalyst may have an effective life of 12–18 months and only small quantities are added between turnarounds. At the end of the operating period, the entire catalyst charge is removed and either reclaimed or sold for its salvage value. For unit cost accounting, some companies may expense the initial charge, as well as any subsequent additions. Others may amortize the initial charge over the life of the unit or over the effective life of the catalyst itself. From a unit cost accounting viewpoint, the preferable method would be to amortize the net cost (after crediting the cost for the salvage value of the spent material) over the effective life of the catalyst itself. With complete replacement at turnarounds, the amortization of the initial charge over the life of the unit is illogical for unit cost accounting (i.e., complete replacement at 12 months versus a unit life of 15 years).

   C. It should be noted that some catalysts have an effective life of many years before recharging is required.

5. Proper accounting for catalysts must include coordination of the amount capitalized, the appropriate life, the accountability of reclamation credits, and treatment of sales proceeds or salvage value of spent catalysts.

4.41.1.6.8.2.2 (12-03-2013)
Depreciation

1. Depreciation in refinery operations is discussed in *IRM 4.41.1.6.7*. *Exhibit 4.41.1-21* provides some useful examination techniques for catalyst accounts.

2. It is not feasible to provide guidelines for a specific processing unit or specific catalyst. However, with some understanding of how catalysts are used and with a review of the taxpayer's internal product cost accounting, the examiner should be able to properly resolve any problem areas. Engineering assistance is available for resolving questionable areas.

3. The precious metal used in the catalyst is not consumed and very little is ever lost. To the extent that the precious metal is not used or ever lost, it is not subject to exhaustion, wear and tear or obsolescence and therefore not depreciable.

4. The following authorities are frequently cited when precious metal catalysts are involved:

   A. Rev. Rul. 90-65, 1990-2 CB 41, provides that the refiner's platinum is economically recoverable for reuse in its business with no loss of utility, the capitalized platinum is not depreciable. the cost of any platinum not recovered is a material or supply expense under IRC 162

   B. Rev. Rul. 97-54, 1997-2 CB 23, provides that the cost of recoverable line pack gas or recoverable cushion gas is not depreciable, but the cost of unrecoverable line pack gas or cushion gas is depreciable under IRC 167 and 168

   C. In *Shaughnessy v. Comm'r, 332 F.2d 1125 (8th Cir. 2003)* the court addressed the use of molten tin to manufacture flat glass. The court held that the tin underwent "exhaustion and wear and tear" within the meaning of IRC 167 and the initial volume of tin was subject to depreciation under IRC 168. If examiners encounter an issue where taxpayers are relying on this case to depreciate their precious metal catalyst, examiners should distinguish the facts of the precious metal catalyst used and cite Rev. Rul. 90-65, 1990-2 CB 41, which specifically describes the treatment of precious metal catalysts. In Rev. Rul. 90-65 (Situation 2), a petroleum refiner used a catalyst, which was over 50 percent composed of platinum. Of the spent catalyst (15-20 percent), 80 to 85 percent of the platinum was recovered and included in a refabricated catalyst. The Ruling explained that "because the refiner's platinum is economically recoverable for reuse in its business with no loss of utility, the capitalized platinum is not depreciable" . Examiners should consider contacting their Local Counsel and the appropriate Technical Subject Matter Experts. Examiners should also be aware that taxpayers might be taking such positions on Form 3115, Change of Accounting Method.

5. Excluding the cost of recoverable precious metals (and in some cases, the cost of nonprecious metals), the cost of nonrecoverable previous metals and the other capitalized costs of the catalyst charged to a process unit are depreciable. The Taxpayer has the burden of establishing the useful life of the nonrecoverable precious metals. for example, where a taxpayer sends a spent catalyst for precious metal reclamation so that the precious metals in the catalyst are recovered for reuse, a taxpayer may be able to prove that a certain percentage is lost per a reclamation cycle. Over the course of several reclamation cycles, the taxpayer may be able to prove that a certain amount is lost over a measurable period of time. In regards to the other capitalized costs of the catalyst charged to a process unit, the useful life may be either the life of the processing unit or the life of the catalyst.

6. Examiners should be aware that as of this IRM revision, the Office of Chief Counsel, Income Tax and Accounting division, has tentatively decided to revoke Rev. Rul. 75-491 and Rev. Rul. 90-65. Published guidance discussing these matters is forthcoming. Examiners are advised to consult their Local Counsel and the appropriate Technical Subject Matter Experts for the latest guidance.

4.41.1.6.8.3 (12-03-2013)
Extraordinary and Casualty Losses

1. Refineries are prone to have fires and explosions occasionally due to the inherent nature of refining operations and the highly volatile nature of the products involved.

2. The agent should check local publications, company news items, annual reports, and SEC filings for such losses.

3. If an extraordinary loss has occurred in a year under examination, the agent should determine if there has been a write-off concerning the casualty loss.

4. Any casualty loss claimed should be verified to determine that the write-off is limited to the property lost in the casualty and that proper consideration has been given to potential insurance recoveries. Treas. Reg. 1.165-7(b) prescribes that the deductible casualty loss is the lesser of the amount of the loss (as determined per the two methods in Treas. Reg. 1.165-7(a)(2)) or the amount of the adjusted basis of the property involved. The two methods for determining the amount of the loss are generally:

   A. competent appraisal of the change in fair market value before and after the casualty and

   B. the cost of reasonable repairs to return the damaged property to the condition prior to the casualty. Refer to Treas. Reg. 1.165-7(a)(2) for more detail.

5. The casualty loss may involve lawsuits and damages of property owned by unrelated parties. The agent should check for contingency reserves which have been set up for the possible liability resulting from the casualty.

6. Two of the more disputed issues with casualty losses are:

   A. the interplay of IRC 162 and IRC 165 for casualty repair expenses and

   B. single, identifiable property ("SIP") related to the basis limitation. Both are discussed below.

4.41.1.6.8.3.1 (12-03-2013)

Interplay of IRC 162 and IRC 165 for Casualty Repair Expenses

1. Directive issued April 27, 2007 alerts the field of a growing trend in the utilities and telecommunications industries whereby some taxpayers are deducting casualty losses under IRC 165 and also deducting the cost of restoring the damaged property as repair expenses under IRC 162. The Service's position is that a taxpayer cannot take a casualty loss deduction and a business repair deduction as a result of the same casualty. If a casualty loss is taken, the repairs must be capitalized under IRC 263(a). Refer to Generic Legal Advice Memorandum 200606 (AM 200606), which primarily cites Rev. Rul. 71-161, 1971-1 C.B. 76..
2. The Service's position was formally stated in the temporary capitalization regulations, generally effective January 1, 2012. Taxpayers must capitalize amounts paid to restore a unit of property per Treas. Reg. 1.263(a)-3T(i). The regulation further clarifies that repairs of damage to a unit of property resulting from or relating to a casualty loss under IRC 165, for which the taxpayer has properly taken a basis adjustments, are restorations. Thus, these repair expenses related to casualty losses are restoration expenses and should be capitalized. for more assistance on capitalization regulations and casualty losses, examiners should contact Local Counsel or the appropriate Subject Matter Expert.

4.41.1.6.8.3.2 (12-03-2013)
Single Identifiable Property (SIP)

1. Directive issued June 19, 2009 provides guidance to the field in determining the SIPs that may be used by an electric utility for its transmission and distribution properties, in calculating its casualty losses under IRC 165. Some taxpayers have designated their entire utilities transmission and distribution system or their entire telecommunication system as the SIP.
2. The rationale of the "single, identifiable property" rule is to arrive at a logical, reasonable, and practical unit for valuation and accounting purposes, while preventing the borrowing of basis from unharmed property, without segregating the damaged property into artificially small subunits. In making these determinations, the field should consider the specific facts and circumstances of the taxpayer, taking into account the factors utilized by the courts as summarized in TAM 200902011.
3. Factors listed in TAM 200902011 to be considered in determining a SIP include:
   - whether the unit chosen is reasonable in relation to the nature and scope of the casualty;
   - whether it reflects all the physical damage caused by the casualty;
   - whether it remains constant and identifiable for tax purposes, and has a cost or adjusted basis that is not changed except by elimination of an asset or by injection of capital;
   - whether it is consistent with the taxpayer's other tax accounting practices;
   - whether it is accounted for and identifiable as a unit for non-tax accounting purposes;
   - whether it is a unit whose utility derives from its functioning as a whole;
   - whether it is separately treated for operational and management purposes;
   - whether it is a commercially segmentable unit likely to be bought or sold as such; and
   - whether it is consistent with industry practice.
4. For casualty losses involving damages to refinery assets, an IRS Engineer should be consulted in determining the appropriate SIP and the adjusted basis of those assets.
5. Most refineries are comprised of a mixture of very old assets that are fully depreciated and newer assets with substantial remaining basis. Examiners should pay particular attention to taxpayers that are "borrowing basis" from assets not involved in the casualty by proposing an inappropriately large SIP. For example, it would be inappropriate to treat an entire refinery as the SIP even though the damage is limited to older assets that are not functionally related to the new assets. Nearly all refineries have redundancy for important assets, and often operate with substantial assets out of service for maintenance.

4.41.1.6.8.3.3 (07-31-2002)
Abandonments and Discontinued Operations

1. Examiners should insure that any deductions for property claimed to be worthless are valid.
2. Examiners should ascertain whether the plant has actually been closed permanently or is merely being placed on a standby basis. This can often be determined in the following ways:
   A. A review of corporate minutes or other internal documents should ascertain who authorized the shutdown or abandonment.
   B. A review of maintenance expenses could disclose extensive maintenance not normally present in an abandoned plant.
   C. Contacts with local taxing authorities will often provide data as to any changes in assessed valuation of property in question.
3. In the event the taxpayer claims the loss as a result of suits brought by environmental groups or agencies, the examiner should ascertain the status of pending appeals.
4. Examiners should insure that property held to be abandoned is not being offered for sale.
5. When facilities are shutdown (abandoned or placed on standby) and the expensive catalysts are recovered, was proper tax accounting treatment given to the recovery and disposition of such catalyst?
6. Examiners should also be certain to review Schedule M for any possible differences between book and tax treatment.

4.41.1.6.8.3.4 (12-03-2013)
Fines, Penalties, and Payments in Lieu of

1. Fines and Penalties can be common in the oil and gas industry because of the nature of operations, especially for refineries. Most commonly, they are due to violations of EPA (http://www.epa.gov/) regulations on atmospheric emission or discharge into waterways or groundwater. However, they can also be due to violations of OSHA (http://www.osha.gov/) safety rules. The upstream segment could have fines or penalties related to underpaid oil and gas royalties from production on federal or Indian lands.
2. No deduction is allowed for any "fine or similar penalty" paid to a government for the violation of "any" law, IRC 162(f) as enacted by Public Law 91–172 (1969). The Senate Finance Committee made the following statement regarding IRC 162(f) in comments explaining section 310 of the Revenue Act of 1971, P.L. 92–178, "In approving the provisions dealing with fines and similar penalties in 1969, it was the intention of the committee to disallow deductions for payments of sanctions which are imposed under civil statutes but which in general terms serve the same purpose as a fine exacted under a criminal statute."

3. Treas. Reg. 1.162–21(b) provides that a fine or similar penalty includes an amount paid or incurred in settlement of the taxpayer's actual or potential liability for a fine or a penalty (civil or criminal). However, civil compensatory or actual damages are not fines or penalties and are therefore deductible under Treas. Reg. 1.162-21(b)(2). In contrast, punitive damages are not deductible.

   Note:

   Criminal fines and penalties are always non-deductible, even if remedial in nature. Refer to *Allied-Signal Inc. v. Commissioner* , CIR TC Memo. 1992-204

   .

4. It should be noted that a payment in lieu of a fine, or a payment made as a compromise of such a liability takes on the character of the underlying asserted obligation and it is similarly nondeductible, *Adolph Meller Company* F2d 1360 (Ct. Cl. 1979). Amounts deducted as contributions may, in fact, be made as a settlement of, and in lieu of, a penalty or under an agreement for nonprosecution involving a fine or a penalty (civil or criminal). It is well established that, "a contribution or gift, for the purpose of section 170, is a voluntary transfer of money or property made by the transferor without receipt or expectations of financial or economic benefit." , Rev. Rul. 76–257, 1976–2 CB 52 and Rev. Rul. 79–148, 1979–1 CB 93 determined that the amount paid by the taxpayer to the charitable organization in satisfaction of a judgment or as a condition of probation by a federal district court is "not deductible under IRC 162(a) of the Code because the amount paid was a fine for purposes of section 162(f)." Furthermore, this ruling holds that such a payment does "not qualify as a charitable contribution, it is not deductible under section 170 of the Code."

5. The examiner should be alert to identify fines and penalties which may be erroneously classified and/or inadvertently claimed as a deduction. Also, a deduction claimed in subsequent year(s) via a Schedule M adjustment requires a review of the earlier year's basis for the payment.

4.41.1.6.8.3.5 (12-03-2013)
Settlements of Environmental Law Violations

1. Are settlements punitive or remedial? Under the "Origin of Claim Doctrine" , examiners should first look to the underlying statute to see if its purpose is punitive or remedial. Legislative history can provide guidance. If a statute is both punitive and remedial or compensatory, or if the lawsuit covers both statutes, then the examiner should obtain and review the settlement agreement. If the settlement agreement is not clear on penalties, requesting the original lawsuit can clarify. If no lawsuit was filed, then review all the facts and circumstances through documents, testimony, or substantiating material. The burden is on the taxpayer to support any amounts deducted as compensatory. Refer to *Talley Indus. v. Comm'r*, CIR TC Memo 1999-200.

2. Subject to the EPA's discretion, as part of the settlement, an alleged violator may voluntarily agree to perform an environmentally beneficial project in exchange for mitigation of some or the entire proposed penalty. These projects are generally called Supplemental Environmental Projects (SEPs) or Beneficial Environmental Projects (BEPs). Examples include:

   - purchase and donation of land for conservation purposes
   - restoration of damaged habitat
   - implementation of public health projects such as mobile asthma clinics

In addition, violators have been required to add pollution control equipment to their plants, build water treatment plants or construct other types of real or personal property as part of a SEP.

3. The tax treatment of SEPs is the subject of a Coordinated Issue Paper http://www.irs.gov/Businesses/Coordinated-Issue---All-Industries---Supplemental-(Beneficial)-Environmental-Projects-(SEPs). The paper concludes that a portion of the costs incurred or amounts paid by a taxpayer for the performance of a SEP or similar project under federal or state law may be analogous to a non-deductible fine or similar penalty defined under IRC 162(f). The paper further clarifies that in order to determine whether any of the amounts incurred for the SEP constitute payments in settlement of a non-deductible fine or penalty, the analysis must focus on the nature of the liabilities that results in the SEP, and not the taxpayer's motives for proposing or accepting the SEP or the benefits of SEPs to other parties.

4. Examiners can locate taxpayer specific environmental penalty information at http://www.epa.gov/compliance/data/systems/multimedia/echo.html

4.41.1.6.8.3.6 (12-03-2013)
Obtaining Case Documents from DOJ and EPA

1. IRS subject matter experts liaise with Department of Justice for False Claims Act (FCA) cases or the Environmental Protection Agency attorneys to obtain documents such as settlement agreements. Examiners can search the intranet for current contacts for these agencies and request assistance in obtaining documents not otherwise provided by the taxpayer.

2. For False Claims Act (FCA) cases settled by the Department of Justice (DOJ), certain procedures apply:

   1. The subject matter expert makes the initial request to DOJ. Then the expert provides the examiner the DOJ attorney contact so specific follow-up and details about the penalties and settlement agreement can be obtained.
   2. A Financial Management Information System (FMIS) report may be requested which shows DOJ's disbursement of funds received from the taxpayer to various federal agencies and regulators. In royalty cases, the report may not be as helpful in determining how much of the settlement amounts were single or multiple.
   3. Refer to http://www.irs.gov/Businesses/Industry-Director-Directive-on-Government-Settlements-Directive-%232 for more guidance on FCA issues.

4.41.1.6.9 (02-19-2008)
Pipeline Right of Way

1. Effective March 8, 1971, the Service modified an earlier ruling and announced its current position on high pressure natural gas pipeline right of way easement, clearing, and grading costs. Refer to Rev. Rul. 71–120, 1971–1 CB 79. The same position was announced for crude oil and petroleum products pipeline costs in IRC 71–448, 1971–2 CB 130.

2. These rulings hold that easement costs (including aerial reconnaissance, preliminary surveys, roddage fee payment to the grantor based on length of the easement, crop damage reimbursement, legal fees, title work, abstract and recording fees) have a determinable life measured by the useful life of the pipeline and are, therefore, depreciable. Since easement costs are similar to a license or franchise, they are considered an intangible asset and will not qualify for any accelerated depreciation. Depreciation of right of way costs must be calculated using the straight line method. See *Panhandle Pipe Line Co. v. U.S.*, 408 F2d 690 23 AFTR 2d 933 (Ct. Cl. 1969).

3. Rev. Rul. 72-403, 1972-2 CB 102, holds that clearing and grading of the right of way are part of the pipeline construction costs and, as such, qualify for accelerated depreciation methods and investment credit when applicable and that initial clearing and grading are not included in any of the asset guideline classes for ADR purposes. Under Rev. Proc. 87-56 1987-2 CB 674 (for MACRS property), initial clearing and grading land improvements as specified in Rev. Rul. 72-403, are excluded from asset class

00.3, Land Improvements, asset class 46.0, Pipeline Transportation, and asset class 49.24, Gas Utility Trunk Pipelines and Related Storage Facilities. The American Jobs Creation Act of 2004 added IRC 168(e)(3)(E)(v), which provides that 15-year MACRS property includes initial clearing and grading land improvements with respect to gas utility property.

4. The costs for the easement and for clearing and grading referred to above do not include expenditures incurred to keep the right of way clear and the pipeline in its normal operating state. Whether such expenditures are ordinary and necessary expenses or capital expenditures requires a determination based on facts and circumstances of each case.

4.41.1.6.10 (02-19-2008)
Inventory in the Pipeline

1. In order to maintain pressure and effect uninterrupted flow or transportation of natural gas to purchasers through pipelines, it is necessary to maintain a certain volume of gas in the lines at all times. This volume of gas is called "line pack" by the industry. Some taxpayers will expense this cost as ordinary and necessary business expense. Some may attempt to capitalize this cost as part of the pipeline cost and depreciate it over the life of the pipeline.
2. Charges incurred by retail gas utilities obtaining natural gas for resale are includable inventory costs. These costs include damage charges, capacity charges, injection charges, storage charges, withdrawal charges, delivery charges, among others. Refer to Rev. Rul. 66–145, 1966–1 CB 98.
3. While it is true that only oil will be flowing through the pipeline, different grades of oil may be in the pipeline at the same time. It is possible to space different grades of oil by running a cleaning tool (called a pig) and a water spacer between each type of oil. In this manner, it is possible to have many different types of petroleum products in the pipeline at yearend. Therefore, it is necessary to determine, with the help of a petroleum engineer, not only the quantity of the oil in the pipeline but also the type of oil. Once the quantity of the specific types of oil is determined, then the correct price must be applied to arrive at the correct ending inventory.
4. In examining a pipeline, the agent should first determine what type of line is in use (gas or oil). Determine how the taxpayer handles the line pack or oil in the line expensed, capitalized or inventoried. If the costs are inventoried, determine whether all costs pertaining to the inventory are included. If the taxpayer has an oil line, ensure that the costs taken into inventory reflect the correct costs based on the correct type of oil. It is possible that the taxpayer, while correctly including the oil in inventory, may have assigned one cost for the entire oil in the pipeline while, in reality, different prices should have been used since different oils were in transit at year end.

4.41.1.6.11 (12-03-2013)
Alaska Pipeline Depreciation

1. IRC 168(e)(3)(C) defining 7-year property includes any Alaska natural gas pipeline. The term "Alaska natural gas pipeline" refers to the pipe, trunk lines, related equipment, and appurtenances used to carry natural gas but does not include any gas processing plant located in the state of Alaska which has a capacity of 500 billion Btu of natural gas per day and is placed in service after December 31, 2013. If the system is placed in service prior to January 1, 2014, the taxpayer may elect to treat the system as placed in service on January 1, 2014 to qualify for the 7-year recovery period. If placed in service prior to January 1, 2014 and the election is not made, taxpayer would have a 15- or 20 -year recovery period depending on when it was placed in service. If elected, depreciation would not begin until after 2013.
2. This incentive provision is effective for property placed in service after December 31, 2004.

4.41.1.6.12 (12-03-2013)
Natural Gas Line Depreciation

1. Gas distribution lines must be depreciated over 20 years or 15 years depending on when placed in service:
   - Placed in service on or before April 11, 2005 - 20 years
   - Placed in service after April 11, 2005 - 15 years

     Note:

     The 15 year provision (Energy Policy Act of 2005) does not apply to property subject to a binding construction contract or self-constructed on or before April 11, 2005.
   - Placed in service on or after January 1, 2011 - 20 years
2. Natural gas gathering lines must be depreciated over a 7-year recovery period (14 year class life) under the Energy Policy Act of 2005. In addition, the Energy Policy Act of 2005 provides for no adjustment for the allowable amount of depreciation for alternative minimum tax purposes. The 7-year provision does not apply to any property which the taxpayer or related party had entered into a binding contract for the construction thereof on or before April 11, 2005, or in the case of self-constructed property, has started construction on or before April 11, 2005.
3. A natural gas gathering line is defined by IRC 168(i)(17) to include any pipe, equipment, and appurtenance that is:
   A. determined to be a gathering line by the Federal Energy Regulatory Commission, or
   B. used to deliver natural gas from the wellhead or a common point to the point at which such gas first reaches:
      - a gas processing plant,
      - an interconnection with an interstate transmission line,
      - an interconnection with an intrastate transmission line, and
      - a direct interconnection with a local distribution company, a gas storage facility, or an industrial consumer.

4.41.1.7 (12-03-2013)
Intercompany Marine Transportation

1. This section sets forth the circumstances under which the Service will accept the use of Third Party Crude Oil Tanker assessments as a measure of the cost of marine transportation incurred on crude oil between related parties.

4.41.1.7.1 (12-03-2013)
Overview of Marine Transportation

1. One of the major elements in the cost of foreign crude oil and products imported into the United States is the freight charge. Because foreign crude oil and products are typically purchased by U.S. importers f.o.b. the loading port, freight charges are determined separately and are paid by the importer to a related company engaged in the transportation of oil. Examiners should review these intercompany charges to determine if they meet the arm's length standard set by regulations under IRC 482.
2. Average Freight Rate Assessment (AFRA) was one of the principal means used by the oil industry on a worldwide basis to determine intercompany freight charges. Starting in the 1990's many petroleum companies no longer owned crude oil tankers. Today, the ASBA Tanker Broker Panel, LLC provides the industry with independent and anonymous oil tanker rate asssessments.
3. When a U.S. importer pays marine transportation charges directly to an independent shipper for crude oil and products imported into the U.S., such charges are ordinarily allowed as a cost element for the crude oil products.

4.41.1.7.1.1 (12-03-2013)
Historical Use of AFRA (old method)

1. AFRA rates were calculated monthly by the London Tanker Brokers' Panel. The rates were published as of the first day of each month ended on the 15th day of the previous month. AFRA was an average of all charters for vessels in service during a specified period, irrespective of the dates on which the charters were concluded. It included time charters and charters for consecutive voyages, both for long- and short-term periods, as well as single voyages (spot) charters. The charter rates were weighted according to the amount of cargo carried.
2. AFRA rates were expressed in terms of Worldscale, which is widely used in the shipping industry to denominate charter rates between independent parties as well as for AFRA and other purposes. Worldscale published rates, computed in U.S. dollars per metric ton, are cited as "Worldscale 100" or W100.

   Example:

   An AFRA assessment of W60 indicates that the rate for any particular voyage is 60 percent of the Worldscale dollar rate for a chartered voyage.

3. Worldscale rates are revised annually
4. Under Delegation Order No. 153, rescinded December 1, 2011, the Director Natural Resources and Construction, was assigned the nationwide authority and jurisdiction to determine the acceptance of AFRA or other freight rate determination methods as an intercompany charge for shipping of foreign-produced crude oil and products.

4.41.1.7.1.2 (12-03-2013)
Tanker Broker Panels (new method)

1. The ASBA Tanker Broker Panel, LLC (ASBA) is a limited liability corporation comprised of six well-established United States tanker brokerage companies. The IRS has evaluated and monitored ASBA tanker rates on a continuing basis. ASBA is supported by oil companies, oil traders, shipping companies and others.
2. A company importing crude oil may adopt the use of Tanker Rate assessments provided by the ASBA Tanker Broker Panel to compute its intercompany and intracompany marine freight charges. Other Tanker Rate Assessments may be developed and those will be evaluated on a case-by-case basis by examiners.
3. Companies must supply the documentation used to obtain the rates from ASBA to the IRS for each verification.

4.41.1.7.1.3 (12-03-2013)
Transshipment

1. Transshipping charges are those incurred in transferring cargo from one ship directly to another ship or to an on-shore terminal for later loading on another ship. The cost of transshipping is a proper charge to the importer.
2. Transshipping has become significant with the shipment of Persian Gulf and African crude oils to terminals in the Caribbean for later shipment to U.S. ports. The U.S. importer will be charged transportation fees for the two legs of this journey plus a transshipping fee paid to the terminal owner. When transshipping occurs at sea or outside a port listed in the Worldscale service, the U.S. importer will ordinarily request the associations preparing Worldscale to compute special freight rates to the point of transshipment.
3. When the transshipping fees are paid to affiliated companies, such charges should be made at arm's-length standards, taking into account the cost of transferring oil between ships or between ships and terminals and the period of storage, if any. Examiners should analyze such intercompany fees.

4.41.1.7.1.4 (07-31-2002)
Intransit Pipeline Costs

1. Intransit pipeline costs are those incurred in transferring cargo from one ship via pipeline to another, e.g., transferring cargo from a Red Sea port to a Mediterranean seaport via the Sumed pipeline. Pipeline related tariff and other transfer expenses are proper charges to the importer. As with transshipping costs, when intransit pipeline costs are paid to affiliates, they should be at arm's-length.

4.41.1.7.1.5 (07-31-2002)
Lightering

1. Lightering is a charge of unloading a part of a cargo into barges or other small ships to enable the tanker to be berthed in a port which is not large enough to accommodate the tanker when fully loaded. The term lightering has also been used to describe the complete off-loading of a vessel. This has generally been considered transshipping. In either event the cost of lightering is a proper charge to the U.S. importer. When the lightering charge is paid to an affiliate, the charge is subject to the arm's-length standard.

4.41.1.7.2 (12-03-2013)
Deadfreight

1. Deadfreight is the excess cargo capacity on a partially loaded tanker, e.g., a 90,000 dwt ship with a cargo of 60,000 tons of cargo, stores, bunkers, etc., would have 30,000 tons of deadfreight. Tankers may be light loaded for the following reasons:
   - A. To allow them to berth in ports which are not large enough to accommodate the tankers when fully loaded
   - B. Non-availability of sufficient cargo at the loading port
   - C. Lack of sufficient storage space at the discharging port
   - D. Need to transit waterways with draft restrictions
2. Deadfreight is not an allowable charge to the importer when it is incurred for the benefit or convenience of the shipping company.

4.41.1.7.3 (12-03-2013)
Demurrage

1. Demurrage is a charge paid to a vessel owner or operator when a vessel is delayed in port beyond the lay time allowed by contract. The allowed lay time varies with each contract, usually depending on the size and loading capacity of the vessel; however, allowed lay time of 72 hours is common. Demurrage may be allowed if, due to the fault of the seller or buyer of the cargo, loading or unloading is not completed within the allowed lay time.
2. Worldscale volumes include standard tables giving demurrage rates for various size ships. These rates can be used in conjunction with the assessments to determine the amount of demurrage on a particular shipment.

   Example:

   The Worldscale volume gives the demurrage rate for a 90,000 dwt ship as $15,200 per day. If the assessment for the particular shipment is W60, the daily demurrage rate would be $15,200 x 60 percent or $9,120. This rate is equivalent to $380 per hour.

3. Demurrage is an allowable charge to the importer to the extent the importer caused the delay that resulted in the demurrage charge.

   A. The importer is not responsible for vessel related delays such as vessel equipment malfunctions, fueling, late arrival or vessel operations. Storm delays may be shared by both parties.

   B. The importer is not normally responsible for delays at the loading facility. The title to the crude purchased on an FOB basis passes to the importer as the crude is loaded onto the vessel. Delays in the loading port may be paid by the importer and recovered later from the producer or seller.

   C. The importer may be responsible for the demurrage charge at the discharge port when the delay is caused by the importer's employees or facilities.

      Example:

      If the importer's offloading equipment, pipeline or storage facility malfunctioned, the delay would be its responsibility. If the offloading facilities belong to a third-party, they may be responsible for the delay. If the delay is caused by the vessel's equipment, the shipping company is responsible.

   D. Demurrage is incurred when the actual time for the voyage exceeds the contract time. If there is no specific identifiable cause for the delay it will be assumed to be related to the vessel and the shipping company will not be entitled to demurrage.

4. Demurrage charges are applicable only to the normal delays incurred in loading and discharging cargo. When extended delays are incurred and the delays indicate the ship is being used for storage, the demurrage rate should be adjusted by the examiner to an amount commensurate with on-shore storage, if appropriate. Such adjustments must be made on a case-by-case basis. Delegation Order No. 153 which was previously applied, was rescinded December 1, 2011.

4.41.1.7.4 (12-03-2013)
Other Charges

1. Charges such as insurance, fees, and taxes not included in the Worldscale will be allowed to the U.S. importer or to the shipper in accordance with industry practice.

4.41.1.8 (12-03-2013)
Leveraged Oil & Gas Drilling Partnerships

1. The use of partnerships by investors in certain drilling operations to claim losses and current deductions for intangible drilling and developments costs (IDC) in amounts that the Service contends exceed both the partnerships' actual IDC and the investors' economic outlay is described below. While not all oil and gas drilling partnerships engage in these abusive transactions, it is an area that calls for a heightened awareness by agents examining these partnerships.

4.41.1.8.1 (12-03-2013)
Introduction

1. This section discusses abusive leveraged oil and gas drilling partnerships (LOGDP). Procedures are provided to assist examiners when identifying and handling a LOGDP case.

   Note:

   Many oil and gas partnerships are not engaged in abusive transactions

   . A leveraged oil and gas drilling partnership is abusive when it is formed by use of promissory notes to artificially inflate the partners' interests in the partnership and generate tax deductions far in excess of the actual economic loss.

2. Because of the complex structure of LOGDP, use of a Technical Specialist is highly recommended.

4.41.1.8.2 (12-03-2013)
Partnership Formation and Description

1. The LOGDP are created by a promoter that forms a partnership or multiple partnerships through which investors participate in oil and gas drilling activities. The abuse occurs at the investor level and because this type of transaction is typically created as an enterprise group, is detectable only by auditing the entire group of entities.
2. The oil and gas drilling activities are conducted through a contractual arrangement between the partnership and promoter-controlled entities. A promoter-controlled upper tier entity is responsible for acquiring working interests in oil and gas wells. A promoter-controlled middle tier entity known as a turnkey drilling company (TDC) is designated as the party responsible for providing subcontracted drilling services for the wells. The general structure of a leveraged oil and gas drilling partnership is graphed below.

   Figure 4.41.1-2

   This image is too large to be displayed in the current screen. Please click the link to view the image.

4.41.1.8.3 (12-03-2013)
Description of the LOGDP Transaction and Key Entities

1. The LOGDP abusive transaction involves investors contributing cash and signing a promissory note to a partnership that is generally 2-4 times greater than the amount of cash contributed. The promissory note is typically a long term obligation to be paid at a future date, usually in 15-25 years. The partnership does not loan the investor any money when the note is signed. The transaction involving the Turnkey Contract artificially inflates the partners' interest in the partnership, also known as the partners' "outside basis" and may generate a tax deduction that is several times greater than the cash contributed by the investors.
2. The partnership signs a Turnkey Contract with the promoter controlled TDC. The contract is the basis for the Intangible Drilling Cost (IDC) deduction. The contract price is close to the total cash and promissory notes contributed by the partners. The cash is immediately paid by the partnership to the TDC. Subsequently, the TDC pays the money to the promoter-controlled upper tier entity. The Turnkey Contract includes a turnkey promissory note for the remaining balance. The turnkey promissory note mirrors the promissory note the investor signs with the partnership. Thus, the partnership has an asset and liability for the same amount.
3. The turnkey promissory note is effectively an obligation to make payments to the promoter-controlled TDC for future services; therefore, the payments will be deductible by the partnership as they are made. The turnkey promissory note does not increase the partnership's basis in its assets nor does it give rise to an immediate deduction or an expense that is properly chargeable to capital. Under this analysis, the turnkey promissory note is not a liability of the Partnership for IRC § 752 purposes, and therefore investors cannot increase their interests in the partnership by their share of the obligation.
4. The IDC deduction is facilitated by the Turnkey Contract, and the related promissory notes. Generally, 50 percent of the cash contributed by the investors and none of the note amounts are spent on drilling operations. The contracts and notes are tools that attempt to artificially create basis and tax deductions for which the investors are not otherwise entitled.
5. For further discussion of partnerships, see *IRM 4.41.1.8.6*.

4.41.1.8.3.1 (12-03-2013)
Promoter Entities

1. *Turnkey Drilling Company (TDC)* In the transaction described in IRM 4.41.1.8.3 the TDC does not drill the wells or perform any services. The TDC is a cash basis taxpayer and does not recognize the note portion of the contract as income. The TDC functions to provide a layer between the promoter's upper tier entity that actually contracts with third party operators and the partnership. This allows the note portion of the Turnkey Contract to avoid income recognition and taxation by the promoter.
2. *Managing Partner* It is common for the managing partner or Tax Matters Partner (TMP) to be selected by the promoter. The promoter is typically the "de facto" managing partner who sets the amount of the investors' cash contribution and defines terms of the turnkey promissory notes. In addition, the promoter selects all the well sites and determines the Turnkey Contract Price. The managing partner or TMP generally does not contribute cash and does not have any liabilities. Typically the managing partner has a 1 percent interest in profits and losses. The cash contribution for the managing partner is generally made in a subsequent year by one of the promoter's companies. In some cases it is never made. Hence, the overall effect of the transactions is that the partnership will have an asset that is slightly greater than the related liability. Although the managing partner is authorized to perform many acts and duties by the partnership agreement he does not actually perform any duties and his only real function is to be a figurehead for the promoter.
3. *Subsequent Year Partnerships* It is common for the promoter to create several partnerships in subsequent years with the same investors participating in a new partnership in each subsequent year. Examiners should request subsequent tax returns for inspections.

4.41.1.8.4 (12-03-2013)
Basics of Identifying a LOGDP

1. A typical LOGDP will have large IDC deductions on the tax return or on Schedule K1.
2. In some cases the IDC may be included on the Cost of Goods Sold line or other expense lines on the return so examiners need to review the balance sheet.
3. In addition to the large deduction, the balance sheet will report a large receivable and a substantially similar amount as a note payable or other liability. The receivable will compromise most of the assets. Likewise the related liability will comprise most or all of the total liabilities.
4. In some cases IDC is a separately stated item on schedule K. In some cases IDC is reported in other deductions on page 1 of the 1065. It may not be called IDC. In all cases the IDC is the largest of the expenses deducted on the return.
5. The following sections are designed as a planning tool to help in the pre-exam and field work portions when auditing LOGDP issues. It is imperative that the revenue agent and petroleum engineer collaborate during the course of the exam.

4.41.1.8.5 (12-03-2013)
LOGDP Audit Steps

1. **Review Books and Records**. Although the agent will have primary responsibility for examining the items below, the documentation revealed from the examination of the books and records will often be important to the other specialties working on the case and used in their audit work (for example, engineer or international agent). Integrating complementary skills and working together as a team has proven more effective in factual development rather than having each specialty work in isolation and then assembling a final product at the end.
2. The following describes items helpful in the planning and conduct of the examination. Refer to Exhibits 4.41.1-32 through 4.41.1-40 for recommended IDR's to be issued in LOGDP cases. Additional items for request and review:

1. Partnership Agreement, including all amendments
2. Prospect Agreement
3. Assumption Agreement
4. Subscription Agreement
5. Subscription Note
6. Turnkey Drilling Note
7. Turnkey Drilling Contract
8. Investment proposal or prospectus
9. Other agreements embodied in letters or memoranda
10. Actual drilling contracts and related operating documents

3. **Orientation**. Review *Exhibit 4.41.1-44*, *Glossary of Oil and Gas Industry Terms* for an overview of engineering terms. Determine if TEFRA or Non-TEFRA procedures apply; see IRM 4.31.2, *Pass-through Entity Handbook*.
4. **Risk Analysis**.
   1. Attempt to identify promoter and return preparer through conducting a yK-1 analysis; see IRM 5.20.12.7
   2. Review the K-1 for the partners' classification as a general or limited partner
   3. Assess the likelihood of material participation. *Hint:* consider the address of the partner and location of the partnership (i.e., is the partner in a non-oil state or high-tax state)?

4. Identify all the partners in the partnership to prioritize interviews. See *Exhibit 4.41.1-41*.
5. Consider ordering in status 45 the top five investors' individual tax returns (based on percent ownership)
6. Inspect the investor returns for other abusive tax transactions
7. Determine if IDC is deducted on investors' tax returns
8. Prepare an investor matrix to assist in understanding relationships among investors. See *Exhibit 4.41.1-41*, *Tax Shelter Partner Listing.*

5. **Coordination**. It is likely that other taxing authorities have the same entities under audit. Information sharing allows for a more efficient audit. The agent should work with the Manager and Territory Manager to coordinate with these other authorities. Communication with these agencies must be established through proper procedures.
6. The following steps should be considered:
   1. Coordinate with other divisions (LB&I or SBSE) if the tax returns are not in your division
   2. Establish contact with Governmental Liaison Officer (Disclosure) to obtain information sharing agreements with other taxing authorities (State and Local) where examinations are ongoing
   3. Determine if any of the investors, promoter, or other participants are under criminal investigation or investigation by other agencies and tax jurisdictions (i.e., state, city). Transaction Code 914 on AIMS database means active Criminal Investigation.

4.41.1.8.6 (12-03-2013)
Partnership Audit Steps

1. *Partnership Formation*
   1. determine who formed the partnership
   2. determine how the partnership was formed and what was contributed to the partnership in exchange for an interest in the partnership
   3. determine whether the investors received an investment prospectus or private placement memorandum
2. See Exhibits 4.41.1-32 through 1-40 for additional items to request and review.
3. *Examine Books and Records*
   1. Conduct a functional analysis of the partnership by reviewing actual business operations
   2. Determine if partnership activity reflects that an actual business is being conducted. For example, did the partnership invest in wells that were actually drilled?
   3. Determine if books and records are prepared by partnership, promoter, or third party
   4. Determine if drilling records are maintained by well or vendor
   5. Summons should be considered if information is not being received in a timely manner
4. *Review Cash Activity*
   1. Follow the cash (review checks and deposits) to determine where money was spent. This will identify the actual activity of the partnership and may identify other entities to be audited.
   2. Look for payments to the promoter or promoter-controlled entities, and payments to related entities.
   3. Look for payment of personal expenses and non business expenses.
   4. Determine source of investor capital contribution (e.g. was it their cash or was it borrowed). If cash was borrowed from a party related to promoter, investor may not be at risk.
   5. Compare the actual expenses of the partnership to what is included on tax return and the Schedule K1's.
5. *Interview Questions*. Interview the investors and return preparer after review of books and records. Suggested questions are:

1. What does the investor know?
2. What is the investor's background?
3. How did the investor find out about the partnership? • who did the investor talk to? • what was discussed? • what documents did the investor receive?
4. What information is received from the promoter?
5. When did the investor become a partner?
6. Is there any interaction with other partners?
7. Are there non-tax reasons for investing?
8. What are the financial benefits?
9. Was anyone compensated?
10. Does investor have basis?
11. Is investor at risk for notes?
12. How are notes paid back?
13. What is the extent of the investor's liability for partnership debt?
14. Has the investor made any payments on the debt?
15. Does the investor list the loans on personal financial statements or loan applications?
16. How does the investor intend to pay back the loan?

17. Gain understanding of transactions.
18. Does transaction occur as it is set up on paper?
19. Are the wells actually drilled?
20. Who determines which wells to drill?
21. Does the partnership have a working interest in the wells?
22. Does the transaction have economic reality?
23. Is there a basis for assertion of penalties?
24. What due diligence was done?
25. Can the investor sell his partnership interest?
26. Does the investor participate in management?
27. Can the investor terminate the partnership?
28. If the partnership is terminated, what partnership liabilities did the investor satisfy?
29. Is this an abusive transaction?
30. Is investor involved in similar transactions?

6. Questions should be tailored to gain a full understanding of the promotion, the persons involved in the promotion and the investor's motives for participating in the promotion. Ideally, the interviews should be conducted face-to-face, but if time or money constraints limit this, prioritize interviews and/or conduct by written questionnaire.

   Note:

   Investors are considered third-party contacts. Refer to IRM 4.11.57, *Examining Officer's Guide, Third Party Contacts*.

7. *Notes and Other Documentation*. Should the examination of the partnership notes reveal alleged debt, the examiner and engineer need to share information. Much of the RA's findings will impact the engineer's work. These debt instruments may have an accounting impact (e.g., how the notes were recorded) as well as a technical impact (e.g., how notes were used to inflate alleged drilling costs). The examination of the notes should determine:

   - if the loans are recourse or non-recourse
   - how the notes are repaid
   - if the notes are to a related party
   - if the loans are from the promoter or promoter-controlled entities
   - if there is a valid business purpose to the debt (e.g., does the loan leverage the tax deduction)
   - how the loans are actually repaid. Consider at-risk establishment factors.
   - how much (if any) of an investor's money was used to repay the debt
   - if the repayment plan and period are realistic
   - any prior loans that are outstanding by the partners to determine a history of repayments
   - the validity of any receivables (e.g., subscription notes)
   - if the partners can deduct any loss per IRC 704 by requesting a partnership basis schedule

8. Consider at-risk limitations and passive activity loss rules. Refer to IRC 465,*Deductions Limited to Amounts At Risk,* and IRC 469, *Passive Activities Losses and Credits*.

4.41.1.8.7 (12-03-2013)
Engineer Issues and Responsibilities

1. An engineer may be called upon as an expert or summary witness regarding oil and gas industry practices and customary deal structures. The engineer’s report is a key product. The engineer will perform a functional analysis of the business activities and processes of the partnerships and turnkey drilling companies. The examination will primarily focus on how much money was spent for the actual drilling of any associated oil and gas prospect, and on collecting factual documentation to determine some of the following:

   - the business operations and drilling activity performed
   - whether the promoter owns or controls the Turnkey Drilling Company
   - whether the promoter formed or controls the partnership
   - what business function and actual business activity the Turnkey Driller performs
   - whether the partnership is entitled to the amount of Intangible Drilling Cost claimed on the return
   - the extent and dates of drilling activity actually performed, if any
   - who or what entity actually performed the drilling activity
   - the reasonableness of the turnkey drilling arrangement

2. Consider hiring an outside expert to assist in determining:

   - whether the turnkey price paid by the partnership was reasonable and constituted an arms length transaction
   - whether the terms of the drilling contract were reasonable, customary and within industry standards
   - whether promoter-controlled drilling company or the partnership actually undertook the economic risk of drilling wells

3. To address the above, consider as part of the factual development process whether the term Turnkey Driller and Turnkey Drilling Contract refer to the promoter-controlled entity typically styled as a "Turnkey Drilling Company" and the drilling contract between the partnership and that promoter-controlled entity.

   Note:

A distinction is made between an actual unrelated third party turnkey drilling company in industry and a non-functioning promoter-controlled entity styled as a "Turnkey Drilling Company" that does not perform or contract for the actual drilling.

4.41.1.8.8 (12-03-2013)
Taxpayer Audit Steps

1. The following are recommended audit steps.

    1. Identify the operator of all drilling prospects associated with the partnership.
    2. Determine if the partnership has a working interest.
    3. Identify if there are any wells or activity outside of the United States.
    4. Refer to *IRM 4.41.1.2.4.7.3* for Turnkey Contract issues.
    5. Compare wells actually drilled to wells listed in the document that transfers working interest often identified as a prospect agreement. Note any differences and whether any discrepancy is material to the factual development.
    6. Determine when the wells were actually drilled and whether any invoices were dated prior to the stated or actual formation of the partnership.
    7. Review the dates of the invoices for the wells and note any unusual lengths of time after the well was spudded (e.g., years after the well was drilled).
    8. Determine whether documents from third parties indicate the promoter, a promoter-controlled entity or its contractor, was the primary or sole contact with the actual well operators.
    9. Determine whether the division order or joint interest billing statements were sent to promoter or a promoter-controlled entity, as the named working interest partner for payment.
    10. Determine whether the promoter, promoter-controlled entity or the partnership signed the election letters for well operations.
    11. For each associated partnership, request executed copies of agreements between the Turnkey Driller and any well servicing companies for activities such as well logging, cementing, casing, perforating, fracturing and maintenance.

4.41.1.8.9 (12-03-2013)
Promoter Audit Steps

1. *Promoter Substance Over Form Issues* This section is to be worked jointly by the engineer and agent. Read the documents identifying debt and compare form of transaction to what actually transpired.
2. *Turnkey Drilling Activity*

    1. For each associated partnership, verify whether the promoter-controlled Turnkey Driller actually engaged in drilling oil and gas wells with its own equipment and personnel or arranged for others to perform such tasks through written contract.
    2. For each associated partnership, request executed agreements between the Turnkey Driller (or any other promoter-controlled entity) and any third party drilling company contracted to drill wells for the Turnkey Driller. Determine whether the Turnkey Driller arranged for any wells to be drilled for promoter or a promoter-controlled entity. For each associated partnership, request executed agreements between the Turnkey Driller and any promoter-controlled entities contracted to drill wells for the Turnkey Driller. Note whether the taxpayer or promoter allege the contracts are verbal and no written contracts exist.
    3. Use Turnkey Driller Business Characteristics below to determine if the drilling company was actively engaged in the drilling business. Note whether the Turnkey Contract is alleged to provide extraordinary protection against unforeseen financial expenses.

Turnkey Driller Business Characteristics
Personnel knowledgeable in oil and gas drilling operations
Equipment or other assets to drill oil and gas wells
Written contracts with entities to perform actual drilling operations or well services
Written contracts with entities to arrange for the drilling of oil and gas wells

    4. Perform a comparison of the terms of the promoter-controlled company's Turnkey Contract with those that would typically be included in a Turnkey Contract used in the industry. Note the differences between the promoter-controlled company's Turnkey Contract and the model form Turnkey Contract developed by the International Association of Drilling Contractors.

3. *Promoter Involvement*

    1. Determine whether the promoter was an investor in the partnership. If a contract is between related parties (e.g., promoter-controlled partnership and promoter-controlled Turnkey Driller), are the price, terms, and structure of the contract arms length?
    2. Determine whether the promoter selected the tax matters partner or influenced the management of the partnership by the tax matters partner.
    3. Determine whether the promoter controlled the oil and gas income from any producing wells and used such revenue to pay ongoing drilling and operating costs, with any residual being applied to "interest" due on the notes from the investors.
    4. Identify who determined the turnkey price to charge the partnership. If it was the promoter, determine whether that person had the experience, training or expertise to develop a reasonable price that is credibly associated with the types of risk associated with drilling operations in the oil and gas industry.

4. *Promissory Notes*

    1. Determine whether the investors' promissory notes were used as collateral for payment of a portion of the monetary amount required to drill the wells subject to the partnership agreement.
    2. Determine whether a turnkey promissory note (between the partnership and the Turnkey Driller) was secured by the investor promissory note (Subscription Note between the partnership and the investor).
    3. Determine whether the promissory notes were used as a means to inflate the IDC claimed on the return. Compare the amount of IDC actually incurred to the amount claimed on the return and based on the drilling contract price set by the promoter or promoter-controlled Turnkey Driller (view third-party invoices).
    4. Determine whether the notes are recourse or non-recourse in nature. Is there language in any side agreements that limit the investor's ability or debt repayment

requirement?

5. Is the note to be paid out of future oil and gas revenue in whole or in part?
6. Does the partnership pledge its assets to secure the note?

4.41.1.8.10 (12-03-2013)
Penalty Considerations

1. The LOGDP is an abusive transaction and penalties such as negligence and valuation misstatement apply.
2. Refer to IRM 4.20.1, *Examination Collectibility* and IRM 4.10.6, *Examination of Returns, Penalty Considerations* for guidance.
3. The agent determines if the transaction is tax motivated:
   - Were new investor dollars used to fund prior investments? (Note whether there are elements of a Ponzi scheme.)
   - Review transactions for economic reality
   - Would the investment be reasonable without the tax benefits?
   - Would a reasonable investor invest in this promotion without the tax write-offs?
   - Determine the amount of due diligence by each investor
   - Determine if the investor consulted with an independent third party

4.41.1.8.11 (12-03-2013)
Preparer/Promoter Considerations

1. Consider whether a preparer penalty (IRC 6694) or a promoter examination (IRC 6700) is warranted.
2. Consult with a manager or technical specialist to determine if action should be initiated.

4.41.1.9 (12-03-2013)
Activities and Personal Services Provided on the U.S. Outer Continental Shelf

1. **In General**
   A. The U.S. Outer Continental Shelf (OCS) is the continental shelf adjacent to U.S. territorial waters over which the United States has the exclusive right of exploring for and exploiting natural resources.
   B. Vessel owners (including vessel charterers in the chain between the vessel owner and the operator) and vessel operators may be engaged in activities related to the exploration for, or exploitation of, natural resources on the OCS. These activities include, for example, seismographic testing, drilling services, repair and salvage work, and the transportation of supplies and personnel between U.S. ports and the OCS.
   C. These services generally are carried out by contractors using vessels that are designed and/or modified for a specialized purpose, such as seismographic testing. The contractor may own the vessel, but often leases it from a third party. Depending on their function, the vessels may either stay in the same location for long periods of time or regularly move from location to location. Vessels may be foreign-flagged, and vessel owners and/or operators may be foreign individuals or companies.
2. **IRC 638 and Associated Treasury Regulations**
   A. For purposes of applying Chapter 1 of the Code (which includes rules for sourcing income) with respect to mines, oil and gas wells, and other natural deposits, IRC 638 applies the term "United States" as a geographical reference to include the Outer Continental Shelf.
   B. Under Treas. Reg. 1.638-1(c)(1), persons, property, or activities that are engaged in or related to the exploration for, or exploitation of, mines, oil and gas wells, or other natural deposits (collectively known as IRC 638 activities) don't need to be physically on, or connected or attached to, the seabed or subsoil of the OCS to be deemed within the United States.
   C. Treas. Reg. 1.638-1(c)(4) clarifies that persons, property, or activities are within the United States only to the extent they are engaged in Section 638 activities.
   D. Section 638 activities are not limited to exploration and exploitation. Activities must merely be related to the exploration for or exploitation of natural resources in the OCS to be section 638 activities.

      Note:

      In PLR 200823005, foreign-owned and leased vessels were engaged in the removal and repair of underwater oil and natural gas pipelines; the inspection, maintenance, and repair of production platforms and wellheads; and the salvage of pipelines and production related equipment. The Ruling concluded that *" Although the services do not constitute the actual drilling of oil and gas wells, such repair and remediation of oil and gas infrastructure are clearly related to the exploitation of natural resources, and fall within the ambit of Section 638."*
   E. Treas. Reg. 1.638-1(d)(1) defines natural deposits and natural resources as nonliving resources to which Section 611(a) applies (e.g., the depletion deduction). Natural deposits and natural resources do not include sedentary species, fish, or other animal or plant life.
3. **Tax Consequences of the OCS being in the United States**
   A. IRC 638 activities may give rise to U.S. source income.
   B. Accordingly, a foreign corporation that derives income from section 638 activities may be taxable in the United States. If the foreign corporation is engaged in a U.S. trade or business and the income is effectively connected with that U.S. trade or business, tax is imposed on that income at graduated rates on a net basis under IRC 882(a).
   C. If the foreign corporation is not engaged in a U.S. trade or business, tax is generally withheld on U.S. source income on a gross basis at a 30 percent rate under sections 881(a), 1441, and 1442.

D. If the foreign corporation is a resident of a country with which the United States has a bilateral tax treaty, it may be exempt from withholding, or eligible for a reduced rate of withholding.

E. A foreign corporation that is claiming a reduced rate of withholding tax or an exemption from withholding tax must file a W-8BEN with the withholding agent, generally the payor. See regulations under IRC sections 883, 1441, and 6114, and consider contacting an International Technical Specialist or an International Examiner.

F. A vessel engaged in section 638 activities is generally not deriving income from the international operation of a ship, which is often exempt from tax under a treaty or section 883. Examiners should ensure that income characterized as from international transportation activities is not in fact from section 638 activities.

G. If a foreign entity operating in the OCS is claiming it is exempt from U.S. tax, Examiners should verify the foreign entity's activities and the legal basis for its claim. This might include, for example, reviewing contracts and the types of vessels being used by the foreign entity.

H. The following U.S. reporting may be required in connection with section 638 activity:

- Form 1120-F (U.S. Income Tax Return of a Foreign Corporation) for foreign corporations engaged in a U.S. trade or business.
- Form 1042 (Annual Withholding Tax Return for U.S. Source Income of Foreign Persons) filed by withholding agents that withholding tax on U.S. source payments to foreign corporations not engaged in a U.S. trade or business.
- Form 8833 (Treaty-Based Return Position Disclosure Under section 6114 or 7701(b)) (for foreign corporations claiming an exemption from, or reduced rate of, tax under the provisions of a treaty)
- Form 941 (Employer's Quarterly Federal Tax Return) (for foreign corporations conducting section 638 activities that are required to withhold employment taxes from remuneration to employees).

4. **Withholding**

A. As discussed above in Tax Consequences of the OCS being in the United States, payments to foreign companies for section 638 activities are generally subject to withholding tax under IRC sections 1441 and 1442.

B. A withholding agent is defined in Treas. Reg. 1.1441-7(a)(1) as any person, U.S. or foreign, that has the control, receipt, custody, disposal, or payment of an item of income of a foreign person subject to withholding. A withholding agent may be an exploration and production company, a project manager, or a contractor.

C. Residence is not relevant to determining whether a person is a withholding agent. Foreign and U.S. persons can be withholding agents.

D. A foreign company claiming an exemption from withholding under a treaty must file a Form W-8BEN (Beneficial Owner's Certificate of Foreign Status for United States Tax Withholding) with the withholding agent.

E. An Examiner should review all Forms W-8BEN provided to withholding agents. If the treaty benefit being claimed by the foreign companies is not consistent with the facts (for example, a foreign company with modified and specialized vessels that claims to be engaged in international transportation), the examiner should consider whether the withholding agent should have filed a withholding tax return (Form 1042), and is liable for failing to withhold tax.

5. **Treaty Claims**

A. Treaty claims must be examined closely because U.S. bilateral treaties vary from country to country and some treaties (e.g., Norway) have special provisions with respect to Section 638 activities.

B. In particular, there is a wide variation among treaties over how of the terms permanent establishment and business profits are defined.

C. To be eligible for a treaty benefit, a foreign corporation must be a resident of the foreign county with which the United States has a treaty; qualify under the Limitation on Benefits article in the treaty; and meet any additional requirements under the treaty article for which it is claiming the benefit.

D. Special attention must be given to a foreign entity's claim that it is exempt from tax under a treaty because it does not have a permanent establishment. A mine, oil or gas well, quarry, or any other site where natural resources are being extracted will give rise to a permanent establishment if the activity is continuous and of a certain duration. The duration may range from 90 days (e.g., the U.S.-Canada treaty) to 12 months. Special treaty provisions apply to income that is attributable to a permanent establishment.

E. A foreign company claiming an exemption from, or reduced rate of, U.S. tax under an income tax treaty generally must attach a Form 8833 (Treaty-Based Return Position Disclosure under section 6114 or 7701(b)) to its Form 1120-F setting forth:

1. the treaty position and article it is relying upon for the exemption from or reduced rate of tax;
2. its country of residence; and
3. an estimate of the gross income that is exempt from tax.

Failure to disclose a treaty-based return position may result in penalties under section 6712.

6. **Field Directives**

A. Industry Directors Directive # 1 - United States Outer Continental Shelf Activity, published October 28, 2009. See Industry Director's Directive #1 - United States Outer Continental Shelf Activity.

B. Industry Directors Directive # 2 - Employment Tax and the Employees on the U.S. Outer Continental Shelf, published March 30, 2011. See Industry Director's Directive # 2—Employment Tax and the Employees on the U.S. Outer Continental Shelf.

Exhibit 4.41.1-1
Research Material Available, Oil and Gas Taxation

A. *Oil and Gas Taxes*, Prentice Hall, Inc.
B. The RPI Primer of Oil Exploration, Drilling and Production, Resource Programs, Inc.
C. A Primer of Oilwell Drilling, PETEX, The University of Texas at Austin
D. Bulletins published by the Council of Petroleum Accountants Societies of North America (COPAS)
E. Primer of Oil and Gas Production, American Petroleum Institute

F. *Oil and Gas Quarterly*, Matthew Bender & Co., Inc.
G. *Oil and Gas Journal* (published weekly), PennWell Publishing Co.
H. *Manual of Oil and Gas Terms*, 14th Edition, Williams and Meyers

Exhibit 4.41.1-2
Division of the Production From Oil and Gas Property

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Exhibit 4.41.1-3
Useful Examination Techniques — Lease Acquisition Costs

1. Scan the non-producing lease account in the asset section of the ledger to determine the number of oil and gas leases acquired during the year and their names.
2. Test lease operating costs, legal and accounting, office supplies, miscellaneous, and similar accounts for acquisition costs that may have been deducted as current expenses.
3. Inquire about the taxpayer's method of allocating overhead costs to the leases acquired. Are land department costs, salaries of geological departments, and administrative costs included in the cost of properties acquired? Request copies of authorization for expenditures (AFE) for lease purchases to see if direct costs are set out as part of the cost of the property.
4. Test the delay rental account for bonuses that may have been charged to expense in error.
5. Has the taxpayer allocated leasehold cost correctly on producing leases purchased? Do you need engineering assistance?
6. Scan and test the chargeoffs of geological and geophysical expenses to determine if they should be capitalized as cost of drilling projects acquired.
   a. Were seismic costs incurred in areas where leases were acquired?
   b. Have commissions to geologists or consultants been incorrectly deducted as IDC?
   c. Have seismic survey projects really been abandoned without acquiring leases? Scan subsequent year acquisitions. (Some lessors, such as state or Federal government, put selected lands up for lease each year and hold other lands to put up for future years.)
   d. Questionable deductions should be brought to the attention of an IRS petroleum engineer.
   e. See Rev. Rul. 77–188, 1977–1 CB 76 and Rev. Rul. 83–105, 1983–2 CB 51.

Exhibit 4.41.1-4
Useful Examination Techniques — Intangible Drilling and Development Costs

1. Determine if the taxpayer has made a proper election to deduct IDC as a current expense.
2. Test the larger deductions in the intangible development expense account.
   a. Schedule large amounts
   b. Request invoices
   c. Request AFEs
   d. Compare above documents with amounts claimed
3. Inspect the drilling contracts on a selected basis, especially December deductions.
4. Determine if prepaid IDC is required by the contract, or if it is merely a deposit, and whether or not paid directly to the drilling contractor.
   a. Determine when the well was "staked" and when work was started.
   b. Consider the facts surrounding the prepaid IDC in relationship to Rev. Rul. 71–579, 1971–2 CB 225, and 71–252, 1971–1 CB 146.
   c. Consider the effect of an adjustment. Does the adjustment have tax significance or would it be a mere "rollover?" (remember timing of IDC deduction could affect the net income limit for percentage depletion under IRC 613A).
5. Scan the depletion schedules to determine which newly acquired leases are productive.
   a. Have the drilling costs been shown as a deduction on the leases for the 100-percent percentage depletion limitation?
   b. Prepare a list of new productive leases from the depletion schedule.
6. From the list prepared in item 5(b), request the lease files on all new productive leases, or on a selective basis if the number is large.
   a. Review the lease files to determine if the taxpayer's ownership percentage corresponds with the amount of IDC deducted. If not, why? Is the deduction allowable?
   b. Review assignments, correspondence, and related documents to determine if the taxpayer has drilled for his/her interest in the lease and if he/she is "carrying" other owners.
   c. If transactions as described in (a) and (b) are found, has the taxpayer handled them correctly? See Rev. Rul. 70–657, 1970–2 CB 70; Rev. Rul. 71–206, 1971.1 CB 105; Rev. Rul. 69–322, 1969–1 CB 87; Rev. Rul. 77–1 76, 1977–1 CB 77, etc.
7. Scan the producing lease account in the asset section of the ledger.
   a. Note the leases that have been removed (credits).
   b. Have the leases removed been reported as sales?
   c. Should IDC be recaptured in accordance with IRC 1254?
8. Allocate a reasonable amount of administrative overhead costs to IDC for tax preference purposes before computing the minimum tax.
   a. Usually, this can be done by allocating overhead based upon the direct departmental costs.
   b. In many cases, this can be easily accomplished by using the taxpayer's workpapers prepared for the purpose of allocating overhead for depletion purposes.
9. Taxpayers must own the entire working interest during the complete payout period to be allowed to deduct 100 percent of the IDC in a carried interest arrangement.
10. Has surface casing been deducted?
11. Has IDC been shown in operating expenses incorrectly to avoid minimum tax under IRC 57 or recapture under IRC 1254?

Exhibit 4.41.1-5
Classification of Expenditures in Acquisition, Development, and Operation of Oil and Gas Leases

A. Leasehold Cost (Capital Expenditure)

1. Research of lease location by engineer, geologist, etc., for purposes other than locating a well site.
2. Geological and geophysical expenditure leading to acquisition or retention of an oil and gas property (limited to expenditures after August 8, 2005 for foreign properties; see *IRM 4.41.1.2.2.3.1*).
3. Expenses in connection with leasing the property from a landowner.
4. Legal costs of securing lease and clearing title.
5. Legal fees incurred to obtain access to the property and to obtain easements, etc.
6. Lease bonus paid to the landowner or other owner.
7. Purchase price of an existing lease.
8. Core-hole wells drilled to obtain geological data (limited to expenditures after August 8, 2005 for foreign properties; see *IRM 4.41.1.2.2.3.1*).
9. Cost of seismic work incurred by an oil and gas company to determine the size of the reservoir or reserves (limited to expenditures after August 8, 2005 for foreign properties; see *IRM 4.41.1.2.2.3.1*).
10. Legal fees incurred in drafting contracts.
11. Travel expenses incurred in acquiring leases.
12. Salaries of land department personnel in acquiring leases.
13. Equalization payments paid in furtherance of a unitization when paid in connection with prior IDC.
14. Bottom-hole contribution when paid to obtain information which enhances the value of the property (limited to expenditures after August 8, 2005 for foreign properties; see *IRM 4.41.1.2.2.3.1*).
15. IDC if no election to expense has been made under IRC 263(c) or if "foreign IDC."
16. Delay rentals unless the taxpayer can establish that it was not reasonably likely for the lease to be developed.
17. Remaining basis in equipment which is transferred to another person under any type of reversionary agreement.

B. Intangible Drilling Costs (current deductions or capital cost depending on election)

1. Administrative costs in connection with drilling contracts.
2. Survey and seismic costs to locate a well site on leased property.
3. Costs of drilling.
4. Grading, digging mud pits, and other dirt work to prepare drill site.
5. Cost of constructing roads or canals to drill site.
6. Surface damage payments to landowner.
7. Crop damage payments.
8. Costs of setting rig on drill site.
9. Transportation costs of moving rig.
10. Technical services of geologist, engineer, and others engaged in drilling the well.
11. Drilling mud, fluids, and other supplies consumed in drilling the well.
12. Transportation of drill pipe and casing.
13. Cementing of casing (but not the casing itself).
14. Rent of special equipment and tanks to be used in drilling a well.
15. Perforating the well casing.
16. Logging costs, but not velocity surveys.
17. Costs of removing the rig from the location.
18. Dirt work in cleaning up the drill site.
19. Cost of acidizing, fracturing the formation, and other completion costs.
20. Swabbing costs to complete the well.
21. Cost of obtaining an operating agreement for drilling operations.
22. Cost of plugging the well if it is dry.
23. Cost of drill stem tests.

C. Lease and Well Equipment (Capital Expenditures)

1. Surface casing.
2. Equalization payments of a unitization when paid in connection with equipment.
3. Cost of well casing.
4. Salt water disposal equipment and well.
5. Transportation of tubing to supply yard but not from supply yard to well site.
6. Cost of production tubing.
7. Cost of well head and "Christmas Tree."
8. Cost of pumps and motors including transportation.
9. Cost of tanks, flow lines, treaters, separators, etc., including transportation.
10. Dirt work for tanks and production equipment.
11. Roads constructed for operation of the production phase.
12. Laying pipelines, including dirt work and easements.
13. Installation costs of tanks and production equipment.
14. Construction costs of trucks turnaround pad and overflow pits at new tank battery.

D. Lease Operating Expense (current deduction)

1. Cost of switcher or pumper to operate the wells.
2. Cost of minor repair of pumps, tanks, etc.
3. Grading existing roads.
4. Treat-o-lite and other materials and supplies consumed in operating the lease.
5. Pulling sucker rods, pump, and cleaning the well.
6. Utilities.
7. Taxes other than Federal income taxes.
8. Depreciation of equipment used on the lease.
9. Rental of lease equipment.
10. Salaries for painting and cleaning the lease.
11. Lease signs.
12. Salaries of other operating personnel—farm boss, superintendent, engineer, etc.
13. IDC when elected to expense under IRC 263(c).
14. Salt water disposal costs (other than those under C.4. above).
15. Allocable portion of overhead costs.
16. Qualified tertiary injectant expenses. See Treas. Reg. 1.193–1 and *IRM 4.41.1.3.3.6*.

Exhibit 4.41.1-6
Rules Regarding Foreign Geological and Geophysical Expenditures

When foreign geological and geophysical expenditures are encountered, such expenditures must be capitalized. The tax treatment of foreign G&G exploration expenditures is discussed in Rev. Rul. 77-188, 19771-1 C.B. 76 as amplified by Rev. Rul. 83-105, 1983-2 C.B. 51. These rulings set forth an exploration program is conducted in stages with specific identification of a project area, area of interest, and the acquisition of properties.

1. First, the project area associated with the subject expenditures must be identified. The agent should request copies of the AFEs with respect to expenditures expensed. Generally, taxpayers will incur expenditures regarding reconnaissance type surveys; these are the original or first surveys conducted over a project area. Typically, no specific property (i.e. leasehold) has been acquired at this stage of the project; such reconnaissance type survey costs are held in a suspense account until such time the expenditure may be capitalized to a particular property or an event occurred that enabled the taxpayer to write off such expense.

2. Second, as a result of the reconnaissance type survey, the taxpayer will identify specific geological features that may be conducive for hydrocarbons. Such geological features are defined as an area of interest within the project area. The reconnaissance type survey costs are allocated equally to each area of interest regardless of size or relative costs. The examiner must be aware that taxpayers usually designate many areas of interest so that a large portion of the geological and geophysical costs are capitalized to areas of interest which are abandoned.

3. Lastly, within each particular area of interest have specific properties been acquired. If so, the capitalized geological and geophysical expenditures associated with the area of interest (held in suspense account up to this stage) are allocated to each property acquired based on acreage.

If an entire area of interest proves unfavorable for development (if no lease is obtained), the allocated exploration costs (reconnaissance and detailed costs) are deductible as a loss in the year the area is abandoned. Refer to Treas. Reg. 1.614-6(d). Rev. Rul. 83-105 establishes an identifiable event is a prerequisite for a loss deduction, a decision not to pursue a particular area of interest is not sufficient. Examples of an identifiable event that would trigger a loss deduction include:

- a lease sale occurs and the taxpayer is unsuccessful in acquiring

- data obtained indicates the absence of mineral producing potential

If only a portion of an area of interest proves worthless, a loss cannot be deducted until the complete area of interest is abandoned as a potential source of mineral production. The taxpayer's lease record and the taxpayer's current land map should disclose if the taxpayer holds any leases within the project area.

Example:

The OilCoA, as a result of a preliminary survey work, obtains an option or selective type lease covering 10,000 acres at a cost of $4 per acre, or $40,000. The lease is for a term of 5 years and 6 months. The terms of the lease provide that a minimum of 25 percent of the acreage must be selected before the expiration of 6 months, a bonus of $10,000 per acre must be paid on the selected acreage, and a delay rental of $2.00 per acre per annum be paid on acreage selected. The preliminary survey, core drilling, and other geological and geophysical costs amounted to $24,000. Prior to the expiration of the first 6-month period, OilCoA selected 2,500 acres under the lease which they paid $25,000 bonus. The $40,000 option cost, the $24,000 geological and geophysical expenditures, and the $25,000 bonus should be capitalized as leasehold costs of the 2,500 acres of land selected. The taxpayer may claim an abandonment of 7,500 acres and a loss of 75 percent of the $40,000 option cost plus all or part of the $24,000 geological and geophysical costs paid. This abandonment will appear as a credit to the leasehold account and a debit in the Expired and Surrendered Leases Expense. The leasehold account may explain this credit as "release acreage" when actually the company never had a lease on the acreage, but only an option. The lease record usually identifies a lease by its terms, bonus, acreage, and other provisions, thereby making possible the identification of each lease acquired.

Note:

Remember that all

of the geological and geophysical expenditures incurred in an area of interest are allocated to the acreage acquired and retained in the area. The acreage not retained is outside of the area considered to be favorable for development, regardless of the fact that an option was obtained as a protective measure during the study. See Rev. Rul. 77-188, 1977-1 C.B. 76 and Treas. Reg. 1.234.2. For further explanation of Rev. Rul. 77-188 and detailed examples of the tax treatment of foreign geological and geophysical costs, see Rev. Rul. 83-105, 1983-2 C.B. 51.

Exhibit 4.41.1-7
Information Required Before Maximum Allowable Depletion Can be Computed

What is the taxpayer's average daily production of domestic crude oil and how was it computed [IRC 613A(c)(2)]?

Is the taxpayer required to share the tentative depletable oil quantity with related entities or family members [see IRC sections 613A(c)(3) and (8)]?

If question 2 is "yes" , determine the taxpayer's individual share of tentative oil quantity under IRC sections 613A(c)(3) and (8).

Is the percentage depletion limited to 65 percent of adjusted taxable income?

Are any of the properties marginal oil or gas production properties held by independent producers or royalty owners

Have overhead expenses been allocated to the properties for percentage depletion purposes?

Is the taxpayer a refiner or retailer [IRC 613A(d)(2) or (4)]?

1.

   Note:

   The information above is not needed for a taxpayer with only a few small oil and gas leases because the facts may be obvious. However, for a taxpayer with large production, much time can be saved by obtaining the facts above before making any computations.

Exhibit 4.41.1-8
Steps in the Computation of Depletion for All Taxpayers Other than Retailers or Refiners as Defined in IRC sections 613A(d)(2) & (4)

Steps:

1. Start with a schedule of all properties in which the taxpayer owns an economic interest and has income from production of oil or gas. If the taxpayer is on a tax year different than a calendar year, for computation of percentage depletion under IRC 613A(c), treat each part of a calendar year within the tax year as if it were a "short period" return. Two separate percentage depletion computation schedules are required for a fiscal-year taxpayer. For each property, the allowable percentage depletion deductions from each schedule are combined to compute the property's allowable percentage depletion deduction for the fiscal year. Each property's allowable percentage depletion deduction is then compared with that property's cost depletion deduction. The larger of the two computed deductions is the allowable deduction. The agent should scan the schedule for leases with similar names and consider the effect on the computations if properties with similar names were, in fact, one property as defined in IRC 614. The agent should obtain the lease acquisition and well files for the purpose of determining if these wells were drilled on a single property as defined in IRC sections 614 (a) and if their income and expense should have been reported together on the depletion computation schedule.
2. The schedule below illustrates what a depletion schedule might look-like per the tax return. "ALL" depletion schedules should show and compute for each property the following:

Oil & Gas Depletion

Leases	M	N	O	Y	Total	Notes
Gross Income from Property	$400	$600	$334		$1,334	2a
Direct Operating Expenses	$200	$400	$234	$200	$1,034	2b
Intangible Drilling Costs						2c
Allocable Indirect Expenses	$50	$100	$40	-	$190	2d
Taxable Income from the Property	$150	$100	$60	($200)	$110	2e
Percentage Depletion Computation:						
a. 15% of Gross Income	$60	$90	$50	$ -	$200	2f
b. Net Taxable Income	$150	$100	$60	$ -	$310	
Lesser of a. or b.	$60	$90	$50	$ -	$200	2g
Cost Depletion (From Schedule)	$40	$ -	$10	$20	$70	2h
Tentative Depletion - Greater of Percentage or Cost	$60	$90	$50	$20	$220	2i
Percentage Depletion	$60	$90	$50	$ -	$200	2f

Limited to 65% of Total Taxable Income (Allocated to Property)	$20	$29	$16	$ -	$65 *	3
Greater of: Percentage (as Limited) or Cost	$40	$29	$16	$20	$105	
Percentage Depletion						
(Remaining Properties Using % Depletion)	$ -	$90	$50	$ -	$140	
Limited to 65% of Total Taxable Income (Allocated to Property)	$ -	$42	$23	$ -	$65 *	3
Allowable Depletion before Barrel Limitation	$40	$42	$23	$20	$125	
**Barrel Limitation on Percentage Depletion	$ -	$23	$13	$ -	$36	4
Allowable Depletion after Barrel Limitation	$40	$19	$10	$20	$89	
Depletion Carryover:						
Allowable % Depletion BEFORE Considering 65% Taxable Income Limitation	$60	$90	$50	$ -	$200	2f
Depletion Allowed for the Properties	$40	$42	$23	$ -	$105	
Depletion Carried to Next Year	$20	$48	$27	$ -	$95	5
* Taxable Income as Corrected						
** Based on Depletable Oil Quantity (see explanation below)						

The 65 Percent Taxable Limitation. The tentative percentage depletion determined in Step 1 above may be subject to the 65 percent of the taxpayer's taxable income limitation of IRC 613A(d)(1). Determine the 65 percent of the taxpayer's taxable income by:

Starting with the taxpayer's taxable income per return.

A. Add back to income: Any operating loss carryback (IRC 172); any capital loss carryback (IRC 1212); and in the case of most trusts, distributions to the beneficiaries (see IRC 613A(d)(1)(D)).

B. Add back to income: Any depletion on production from an oil or gas property which is subject on the provisions of IRC 613A(c) (Exemption for Independent Producers and Royalty Owners).

C. In the case of an individual: Subtract the "zero bracket amount."

D. Make appropriate adjustments to income based on audit recommendations.

Multiply the results obtained in above by 0.65. This product is the 65 percent of taxpayer's taxable income limitation. The taxpayer is not allowed Depletion under IRC 613A(c) [percentage depletion] in excess of this amount. If the tentative depletion determined in (i) does not exceed the 65 percent limitation determined above, the tentative depletion is the allowable depletion for those properties. If the tentative depletion determined in (i) exceeds the 65 percent of taxable income limitation determined above. If the tentative depletion computed in (2) exceeds the 65 percent of taxable income limitation, the excess is disallowed. The disallowed percentage depletion must be allocated to each of the properties so that the allowable percentage depletion can be compared with the cost depletion applicable to each property. (The greater of cost depletion or percentage depletion is allowable.) See IRC sections 613(a) and 613A(d)(1).

The Barrel Limitation (Depletable oil quantity). The IRC defines "depletable oil quantity" in terms of barrels per day. It appears that the agent will be better able to make computations and keep the taxpayer's depletion under IRC 613A(c) in perspective if the depletable quantity of oil is expressed in barrels per tax period. We have, therefore, expressed the amount of oil subject to percentage depletion under IRC 613A(c) in barrels per tax period. Include "all" production. Reconcile all production on return. Is production from "flow through entities" included? Spot check price per barrel by dividing gross income by barrels per lease or property. If large differences in price per barrel appears between properties, investigate. Business under common control and members of the same family are treated as one taxpayer, and the tentative quantity must be allocated. See IRC 613A(a)(8). Compute the total of the taxpayer's production of oil in barrels and gas in barrel equivalents for all properties. If the production from the taxpayer's properties exceed 365,000 barrels (1000 barrel per day), then the "depletable oil quantity" will apply. Oil and gas should not be separated for each property. Separate schedules can be prepared for primary production and marginal production. The taxpayer can allocate the barrel limitation to marginal production first, then to primary production. The schedules should provide the information below:

A. Name of the property AND whether it's marginal or not

B. Number of barrels of production for the tax period

C. Convert the gas to equivalent barrels at 1 barrel = 6 MCF of gas

D. Add barrels of oil to barrels of gas to get total production from property

Note:

Percentage depletion disallowed per Barrel or Depletable oil quantity limitation is not carried forward and is lost forever.

Carryover of Percentage Depletion Disallowed from 65 Percent Limitation. IRC 613A(d)(1) provides that any amount of percentage depletion disallowed because of the 65 percent of taxable income limitation will be treated as an amount allowable under IRC 613A(c) in the following year. In the following year, it will still be subject to the 65 percent of taxable income limitation. The amount of percentage depletion disallowed shall be allocated to the respective properties from which the oil or gas was produced in proportion to the percentage depletion otherwise allowable to such properties under IRC 613A(c).

The allocation of disallowed depletion should be computed in a schedule which has the following column headings:

A. Name of Property

B. Cost depletion

C. Tentative allowable percentage depletion

D. Disallowed percentage depletion

Exhibit 4.41.1-9
Allocation of Overhead Expenses

This exhibit is an example of the proper allocation of a company's overhead to the various producing leases. The allocation is based on direct expenses. The allocation is required under Treas. Reg. 1.613–5(a) for the computation of taxable income from the property and the 50 percent of taxable income limitation in computing percentage depletion. See Treas. Reg. 1.613–1.

If a taxpayer has not made an allocation of overhead to the various leases, the agent should scan the depletion computation schedules to decide whether or not an allocation of overhead would probably affect an adjustment in depletion. [How near to the 50 percent (100 percent for taxable years beginning after December 31,1990) net taxable income limitation is the 22 percent, or applicable percent, of gross income?] If adjustment is probable, the agent should scan the unallocated overhead account to determine the proportion that would most likely be allocated to producing leases. If a relatively significant adjustment appears likely, the agent should make the allocation schedule. Computer assistance may be requested in larger cases.

If the taxpayer has made an overhead allocation, the agent should consider the points listed in (2) above. If adjustment to depletion might be significantly affected by a reallocation, the agent should carefully analyze the taxpayer's overhead allocation and verify that it is based on an acceptable method.

Interest expense paid on money borrowed for operating capital is an overhead item which should be allocated to producing and nonproducing activities prior to allocation among the properties. Interest expense paid on money borrowed for investment (equipment, IDC, leasehold, etc.) is a direct expense of those properties and should be allocated to them 100 percent.

If the taxpayer operates his/her properties in conjunction with properties owned by others and charges a fee for services, the fee is not a credit to his/her operating expenses or overhead account; it is an income item. However, to the extent that the taxpayer has expense in connection with earning these fees, the expenses should not be charged to his/her leases.

In examining the allocation, the agent should verify that "nonproducing" activities are consistently treated. If a well was capable of production but was temporarily shut-in (perhaps waiting pipeline connection), its expenses should not be included under nonproducing for allocation between producing and nonproducing activities and also included under producing properties in allocating to the various leases.

Once the allocation is made to specific properties, the agent should verify that the overhead is properly entered in the "line computation" for the property. He/she should be particularly alert for transposition errors between properties with similar names.

Exhibit 4.41.1-10
Items To Consider During Examination

Leases Expired or Forfeited:

A. Obtain list of leases charged off description, etc.
B. Verify cost or basis-expiration date of lease.
C. Review current lease records for evidence of top leasing.
D. Are leases involved in a unitization or other reclassification?
E. Partial abandonments are not deductible.

Intangible Development Costs:

A. Has proper election been made? Treas. Reg. 1.612-4, IRC 59(e), IRC 291.
B. Are there advance payments involved? Rev. Rul. 71-252.
C. Are tangible costs included? Treas. Reg. 1.612-4(a).
D. Do IDC costs correspond to taxpayer's interest in property? How was it acquired?
E. If the taxpayer is a corporation which is an integrated oil company, did it reduce its IRC 263(c) deductions (IDC for years after 1982) by 15 percent as required by IRC 291(b)?

Condemned or Expired Royalties:

A. Determine proper year of deduction based on event taxpayer relied on.
B. Verify tax basis. Has amount been previously charged off?
C. Has taxpayer disposed of title to property?

Dry-Hole Costs:

A. Is expense charged to appropriate property for purpose of computing depletion limitation?
B. Examine contracts; determine existence of dry-hole contributions, bottom-hole contributions, and farm-ins.
C. Do dryhole costs include only abandonments? IDC with respect to dryhole costs are deductible under IRC 263(c) unless taxpayer has elected to capitalize IDC.

Depletion:

A. Is taxable income (before depletion) computed by property? Percentage depletion cannot exceed 50 percent of the property's taxable income for years beginning prior to 1991. For tax years 1991 through 1997, percentage depletion cannot exceed 100 percent of the property's taxable income. For taxable years beginning after 12-31-1997 and before 1-1-2008 and tax years beginning 1-1-2009 and before 1-1-2012, the net income limitation does not apply to domestic oil and gas production from marginal properties (note - no provision covers years beginning after 12-31-2007 and before 1-1-2009).
B. Is depletion claimed on proven properties acquired after 1/1/1975?
C. IRC 613A(d) limits the percentage depletion to 65 percent of the taxpayer's current year taxable income, calculated without considering any percentage depletion deductions.

Gross Income :

A. Obtain detailed schedule of lease operations for current and prior year. (Depletion schedules may serve for this purpose.)
B. Compare reported receipts, by property, secure explanations for all unusual increases or decreases.
C. Test income on run tickets for selected leases and selected months.
D. Working interest income is subject to self-employment tax.

Operating Expenses:

A. Analyze for large unusual expenses; capital expenditures.
B. Legal and professional-geological and geophysical.
C. Determine why some leases have losses.

Alternative Minimum Tax:

A. Percentage depletion in excess of adjusted basis of leasehold as of beginning of year.
B. Excess intangible drilling costs is a tax preference item and should include a portion of the overhead. This preference applies only to costs for which the corporation did not elect the optional 60-month write-off under IRC 59(e) for the regular tax.

Sale of Oil and Gas Properties:

A. Was leasehold basis reduced by allowed or allowable depletion?
B. Recapture post-'75 intangible development costs? IRC 1254.
C. Was a continuing economic interest retained?

Joint Interest Accounting:

A. Are expenses billed to joint owners handled correctly?
B. Is the taxpayer deducting pro-rata share of expenses? Test selected leases-consider those operating at a loss and those with unusually large expenses.
C. Does an increasing credit balance in the oil and gas payout account represent income that should be reported?

Mandatory Referrals:

A. Engineers-
   - Cases with Activity Codes 219-225 & 290
   - Cases with Activity Code 483 and Gross Receipts/Deductions $1,000,000 and above.
B. Financial Products-
   - Cases with Activity Codes 219-225 & 290
   - Cases with Activity Code 483 and Gross Receipts/Deductions $1,000,000 and above.
C. Economist-
   - Cases with Activity Codes 225
   - All CIC Cases
D. Employment Tax-
   - Cases with Activity Codes 223–225
E. Computer Audit Specialist-
   - Cases with Activity Codes 219–225 & 290

Exhibit 4.41.1-11
Useful Examination Techniques—Oil and Gas Income

Reconcile the oil and gas income on the depletion schedule to the taxpayer's books.

Review the depletion schedules or the subledgers and list the leases that are operating at a large loss.

A. Determine the reasons for the losses.
B. If a large loss is not caused by IDC or some unusual expense, request the lease file and oil run tickets.
C. From the lease file, determine if the income-sharing arrangement is proper. Income may have been diverted to production payments, selected entities, or children.
D. Compare the oil run tickets to the oil income reported on a test basis.

Analyze the suspense account for income that should be recognized in the current year.

Verify the accuracy of the oil and gas payout account for joint owners:

A. Does a credit balance represent oil and gas income that the taxpayer should report?

B. If all income received by a operator is posted as a credit to the oil and gas payout account, has the operator transferred his/her share to the income account?

C. Do the debits and credits to the oil and gas payout account balance on a monthly basis? If not, why?

Test the accuracy of oil and gas income reported on selected leases:

A. Compare lease income reported with oil run tickets for selected months.

B. Reconcile differences.

Exhibit 4.41.1-12
Hydrocarbon Series in Petroleum

Paraffin Series (Saturated)

Type formula: C_nH_{2n+2} **Suffix -ane**
Examples
Methane CH_4
Ethane C_2H_6
Propane C_3H_8
Butane C_4H_{10}
Pentane C_5H_{12}
Hexane C_6H_{14}

Isomers of Paraffin Series

Starting with the formula C_4H_{10}, the carbons may be arranged either in a straight chain, or in a branched chain.
The straight chain is designated as normal butane (n-butane) and the branched chain as isobutane. These compounds have entirely different physical properties as well as different chemical (reactive) properties. The number of possible isomers increases rapidly as the number of carbon atoms in the hydrocarbon molecule is increased (i.e., three pentanes, five hexanes, nine heptanes, eighteen octanes, etc.).

Olefin (Ethylene Series Unsaturated)

Type formula: C_nH_{2n} **Suffix -ene or -ylene**
Examples
Methane CH_4
Ethene (Ethylene) C_2H_4
Propene (Propylene) C_3H_6
1–Butene (Butylene) C_4H_8
2–Butene (Butylene) C_4H_8

Napthene Series (Saturated)

Type formula: C_nH_{2n} Suffix -ane
Ring or Cyclic Compounds (Cycloparaffins)

Aromatic (Benzine) Series

Type formula: C_nH_{2n-6} Suffix -ene

Diolefin (dienes) Series (Unsaturated)

Type formula: C_nH_{2n-2} Suffix -ane
System of conjugeted double bonds

Acetylenes (Highly Unsaturated)

Type formula: none Suffix -yne
Contains one triple bond

Exhibit 4.41.1-13
Distillation Fractions — Typical Crude Oil

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Exhibit 4.41.1-14
Petroleum Refining Process Diagram

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Exhibit 4.41.1-15
Illustrative Information Document Request — Accounting System

Shown below are the contents of a typical Form 4564 (*Information Document Request*) which can be used to survey a taxpayer's accounting system.
In order that we might conduct the examination of your tax return in the most efficient manner, we would like to review the accounting system used. Would you please make available the listed items. We would like to have a member, or members, of your accounting department available to answer any questions that might arise.

1. Organization Chart listing key personnel
2. Chart of Accounts & description of accounting system
3. Data Processing Department Systems Manual
4. Tax workpapers
5. Consolidated Profit & Loss Statements

6. Divisional Profit & Loss Statements
7. Analysis of consolidating eliminations
8. Internal Control Manual
9. Internal Audit Procedures Manual
10. Capitalization Policy Manual
11. Cost Accounting Policy Manual

Exhibit 4.41.1-16
Classification of Costs

Classification of costs is necessary in order to determine the most suitable method of accumulating and allocating cost data. The principal methods of accumulating costs are described below.

Function:

A. *Manufacturing.* Costs applied to producing a product.

B. *Marketing.* Costs incurred in selling a product or service.

C. *Administrative.* Costs incurred in policy-making activities.

D. *Financial.* Costs related to financial activities.

Elements:

A. *Direct material.* Material which is an integral part of the finished product.

B. *Direct labor.* Labor applied directly to components of the finished product.

C. *Overhead.* Indirect materials, indirect labor, and the manufacturing expenses that cannot logically be charged directly to specific units, jobs, or products.

Product:

A. *Direct.* Costs which are charged to the product and require no further allocation.

B. *Indirect.* Costs which are allocated.

Department:

A. *Production.* A unit in which operations are performed on the part or product and whose costs are not further allocated.

B. *Service.* A unit not directly engaged in production and whose costs are ultimately allocated to a production unit.

When Charged to Income:

A. *Product.* Costs included when product costs, as defined above, are computed. Product costs are included in inventory and in cost of sales when the product is sold.

B. *Period.* Costs associated with the passage of time rather than with the product. These are closed out to the income summary each period since no future benefits are expected.

Relation to Volume:

A. *Variable.* Costs which change in total in direct proportion to changes in related activity. The unit cost remains the same regardless of volume.

B. *Fixed.* Costs which do not change in total over wide ranges of volume. The unit costs decrease as volume increases.

Period Covered:

A. *Capital.* Costs which are expected to benefit future periods and are classed as assets.

B. *Revenue.* Costs which benefit only the current period and are thus expenses.

Degree of Averaging:

A. *Total.* The cumulative cost for the established category.

B. *Unit.* The total cost divided by the number of units of activity or volume.

Exhibit 4.41.1-17
Examples – Computer Application Programs

Stratification. Divides an account into dollar ranges and accumulates amounts in each range as well as the number of items in each range. The account is then totaled to show total dollars and total items. The stratification program can be applied to all real accounts as well as all nominal accounts.

Regression Analysis. A comparative analysis of certain accounts which have an apparently normal inter-relationship. Prior years are evaluated electronically to determine a range of normality over a representative number of years. Those relationships are then compared against current year account balances and aberrations identified for examination action.

Selected Invoices Listed by Account. After the stratification program has helped identify examination areas, this program protects vouchers within selected accounts and stratas.

Selected Invoices Listed in Filing Sequence. If the original selection (item 3) is not in filing sequence, the vouchers can be resorted to expedite voucher extraction from files.

Vendor Analysis. Identifies number of records, total charges, and all accounts to which the charges of a particular vendor appear.

Cost of Sales.

A. This voluminous area can be examined through use of statistical sampling techniques.

B. Every nonrecurring vendor can be printed. Based upon an examination by exception, nonrecurring vendors may indicate a potential examination area.

Sales. Extraction of sales to foreign affiliates for the purpose of comparing foreign pricing to domestic pricing.

Fragmentation. This program formats invoices (or vouchers) into an unfragmented listing. Can be used for lists by vendors and/or accounts.

Employment Tax Program. Produces a computer generated Form 4668, FUTA tax report, social security data file, and W–4 analysis identifying employees with little or no withholding.

Depreciation. Calculates depreciation on each class of asset by year as each class is capitalized producing a listing by year and class of asset and cost component breakdown.

Foreign Sales. Computes the gross margin on unrelated customer sales and compares with gross margin on related customer sales.

Statistical Sampling. (PAL) Produces random sample of universe and calculates adjustment based on an examined sample.

Analysis of Expenses for Application of Regulation 1.861.8.

Calculation of Foreign Tax Credits.

Examination of Investment Tax Credits.

Exhibit 4.41.1-18
Illustrative Finished Products Inventory

Main Line of Petroleum Finished Products

A. Products tailored to meet rigid specifications by appropriate treating and blending of unfinished stocks and inclusion of additives.

B. Subcategories:

All gasolines	Liquified Petroleum Gas
Special Naphtha	Gas Oils (i.e., Diesel)
Jet Fuels	Fuel Oils
Kerosenes	Asphalt

Specialty Products

A. Generally low volume, high value products manufactured from otherwise saleable stocks.

B. Subcategories:

Lubricating Oils
Finished Waxes and Greases
Petrochemicals

Byproducts

A. Products resulting from processing designed primarily for other objectives.

B. Subcategories:

Sulfur (from quality improvement processes)
Coke (from converting residual stocks)

Exhibit 4.41.1-19
Characteristics of Gasoline Blending Components

		Octane Number	
Gasoline Component	Vapor Pressure (RVP)	Motor	Research
N-butane	52.0	92	93
Reformate	2.8 – 4.2	84 – 88	94 – 100
Hydrocrackate	1.7 – 3.9	73 – 76	75 – 79
Alkylate	4.6	96	97
Straight-run Gasoline	11.1	61	66
Catalytic Cracked Gasoline	4.4	77	92

Exhibit 4.41.1-20
Cost of Production Report

The cost of production report shows all costs chargeable to a department or cost center for the period. Since its principal objective is the control of costs, detailed data relating to total and unit costs are provided. Typically, the cost breakdown is made by cost elements for each department (or cost center). This report is also a good source for summary journal entries at the end of the month.

The cost of production report generally contains three sections:

A. *Quantities.* This section accounts for the physical flow of units into and out of a department.

B. *Costs to account for.* This section accounts for the incurrence of costs that were:

1. In process at the beginning of the period
2. Transferred in from previous departments
3. Added by the department

C. *Costs accounted for.* This section accounts for the disposition of costs charged to the department. Were the costs:

1. Transferred out to another department or to finished goods?
2. Completed and on hand?
3. Still in process at end of the period?

It should be noted that the total of the costs to account for must equal the total of the costs accounted for.

The cost of production report may be very detailed or may only show totals.

The examiner should peruse these sections to ensure that improper adjustments are not being made for tax purposes via Schedule M and that various types of overhead items are being properly allocated.

Exhibit 4.41.1-21
Suggested Techniques for Examining Catalyst Accounts

Review taxpayer's internal accounting manuals to ascertain systems/methods of accounting for catalysts.

Obtain a simplified flow diagram of refinery operations.

A. Identify all units using catalysts
B. Segregate those utilizing precious metals
C. From refinery operating handbooks or manuals, ascertain operational factors (on-going change out versus turnaround change-out, etc.)
D. Obtain specifics as to type of each catalyst

Is spent catalyst reclaimed, sold for salvage value, or junked?

A. If reclaimed:
   1. What are the charges? How handled?
   2. Is there a credit for spent catalyst?
   3. How are the credits handled?
B. If sold, how are the sales proceeds handled?

When precious metal catalysts are involved:

A. What is the total cost of the catalyst?
B. What is the cost of the precious metal?
C. Is the total cost or net cost (less metal) capitalized?
D. How was net cost determined?

When operations involve continuous frequent replenishment of fresh catalyst, was the initial charge capitalized?

A. If so, over what life (life of unit versus life of catalyst)?
B. How were additional expenditures (total or net cost of make-up catalyst added to unit) treated?

Internal cost accounting records for operational purposes/financial purposes may provide additional information.

Exhibit 4.41.1-22
AFRA Computation Method

AFRA

Vessel Category	Abbreviation	Vessel dwt (Long Tons)
Medium Range	MR	25,000–44,999
Large Range 1	LR–1	45,000–79,999
Large Range 2	LR–2	80,000–159,999
Very Large Crude Carrier	VLCC	160,000–319,999
Ultra Large Crude Carrier	ULCC	320,000–549,999

The following is an example of how the multirate AFRA freight charge is computed for a shipment from Forcados, Nigeria to Philadelphia on a 74,499 dwt (long ton) vessel (75,694 metric ton dw. equivalent) loaded July 4, 1997.

1. The vessel size (dwt) determines the AFRA category rate, LR–1 in this example.
2. Multirate AFRA for a 75,694 metric ton vessel loaded in July 1997, is W131.3.
3. The 1997 Worldscale rate for a voyage from Forcados to Philadelphia is $7.40 per metric ton.

Vessel Category	Abbreviation	Vessel dwt (Long Tons)

4. The AFRA rate times the Worldscale rate gives the rate per ton (W 131.3 x 7.40 = $9.69).
5. The actual cargo times the rate per ton gives the total charge:

Vessel dwt (LR–1 Category)	75,694 metric tons
Less: Bunker fuel, water, and stores	(4,694) metric tons
Cargo (actual cargo loaded)	71,000 metric tons
Rate per ton (see 4. above)	$9.69 per metric ton
Total charge per cargo	$687,990

Note:

This example does not include the effect of the fixed rate differential applicable in respect of additional premiums for coverage of Oil Pollution Liability Insurance on vessels carrying crude oil trading to the U.S.

Exhibit 4.41.1-23
Cargo Sharing–Example

Vessel 64,499 dwt (LR–1 category) (65,534 metric ton dw. equivalent)

Voyage: Loading in Puerto la Cruz and Trinidad in July 1997
Discharging in Philadelphia and New York

Related U.S. Importer paying multirate AFRA rates:
30,000 metric ton cargo from Puerto la Cruz to Philadelphia $4.49 per metric ton

Third-Party cargo sharing at spot rate per ton:
30,000 metric ton cargo from Trinidad to New York $6.00 per ton

	Total	Multiport Rate	Related Importer	Third-Party Importer
Cargo (Metric Tons)	60,000		30,000	30,000
Worldscale Rates		$5.64	$4.49	
Multirate AFRA (July 1997)				
For a 65,543 metric ton vessel		W141.2		
For a 30,000 metric ton cargo			W185.9	
Multiport Rate		$7.96		
Single Discharge Rate			$8.35	
Third Party Spot Rate				$7.00
Limitation a.				
Total Cargo 60,000 metric tons X multiport rate ($7.96)				$477,600
Less charge paid by third party [30,000 metric tons X spot rate ($6.00)]				$210,000
Limitation a. Charge				$267,600
Limitation b.				
Related Importer cargo 30,000 metric tons X single discharge rate ($8.35)				$250,500
Amount allowable:				
The lesser of limitation a. or b.				$250,000

Note:

This example does not include the effect of the fixed rate differential applicable in respect of additional premiums for coverage of Oil Pollution Liability Insurance on vessels carrying crude oil trading to the U.S.

Exhibit 4.41.1-24
Computation of Deadfreight and Deadfreight Limitation

In 1976, a 84,000 dwt ton ship is used to transport 55,000 tons of 34 Arab Light crude from Ras Tanura to Philadelphia. The deadfreight was deemed to have been incurred for the benefit of the importer. The draft restrictions at the U.S. importers terminal in Philadelphia is 39 feet. The maximum draft at Ras Tanura is 72 feet.
Loading Began: August 5, 1976

Worldscale rates per ton:

Ras Tanura to Quoin Island	$ .60
Quoin Island to Philadelphia	$15.80
Total	$16.40

Cost of Shipment to the Importer

		Total	Cargo	Deadfreight
Vessel dwt tons		84,000		
Less stores, water, bunker		(2,000)		
tons		82,000	55,000	27,000
Worldscale charge	$16.40			
Vessel AFRA LR–2	x .573			
Charge per ton	$9.397	$9.397	$9.397	$9.397
Total Charge		$770,554	$516,835	$253,719

Cost per barrel:

Conversion of API 34 crude long tons to barrels: 7.4917
Cargo tons: 55,000 x 7.4917 = 412,043 barrels
Total cost: $770,554 412,043 = $1.87 per barrel

Based on the recommended guide for determining port classification, the largest fully loaded vessel that can make the voyage between the ports of loading and discharge under normal operating conditions is a LR–1 category vessel. Deadfreight is allowable to the extent that the cost per barrel does not exceed the cost per barrel had the cargo been carried in a LR–1 vessel.

Worldscale Rate	$16.40
AFRA Rate LR–1 Category	.783
Cost per Ton	$12.84

The barrel cost for cargo based on a fully loaded vessel is computed as follows: Cost per ton $12.84_7.4917 (barrels per long ton) = $1.714. The charge for deadfreight is not fully allowable because the actual charge per barrel exceeds the charge per barrel that would have been incurred had the cargo been transported in a fully loaded vessel capable of clearing the draft limitations of the loading and discharge ports. The allowable deadfreight is computed as follows:

	TOTAL	CARGO	DEADFREIGHT
Shipment Charge based on Vessel size LR–2	$770,554	$516,834	$253,719
Maximum Allowable:			
Cargo 412,043 barrels x $1.714 =	706,242	516,835	189,407
Deadfreight Not Allowable	$ 64,312	–0–	$64,312

Exhibit 4.41.1-25
Computation of Deadfreight Using Multirate AFRA

Caution: This section may be revised.
A vessel of 110,000 dwt moved cargo of 75,000 tons from Bonny Nigeria to the U.S. Gulf Coast. The cargo was loaded in July 1985.

	AFRA Index	WS Rate	Charge per Ton
Actual Vessel of 110,000 dwt	41.7	$ 14.30	$ 5.96
Smallest fully loaded vessel that could carry the cargo	57.2	$ 14.30	$ 8.18
(75,000 dwt x 103 percent) = 77,250 dwt			
Computation of the voyage charge including deadfreight			
1. Total tons carrying capacity			
Vessel dwt			110,000
Less: Bunker			(2,800)
Stores, water, supplies			(350)
Ballast included in dwt			(4,270)
Net carrying capacity			102,580
Deadfreight limitation			
(70 percent of 110,000)		77,000	
Less actual cargo		75,000	
Deadfreight not allowable	2,000		(2,000)
Cargo and deadfreight			100,580
Rate for vessels dwt			x 5.96
Charge based on cargo and deadfreight			$599,467
2. The cargo times the rate for the smallest fully loaded vessel that could carry the cargo			
Total tons loaded			75,000
Assumed vessel gross up			77,250
(103 percent of 75,000)			
Rate per tone for 77,250 dwt vessel			$ 8.18
Actual cargo (tons)			x 75,000

		AFRA Index	WS Rate	Charge per Ton
	Cargo charge for fully loaded vessel			$613,500
				——
3.	Allowable charge The lesser of (1) or (2) above			$599,467
				——

Exhibit 4.41.1-26
Analysis of SPE Factual Scenarios of Probable Reserves

Scenario No. One: ***Reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved.***

A. A well to be drilled as a "normal step-out" is a well to be drilled into an extension of a known deposit. Whether a well is a normal step-out is a question of fact. Proximity to producers is usually indicative of such existence. These types of wells are sometimes referred to as "one location step-outs." Refer to Rev. Rul. 77-136, 1977-1 CB 167, Exhibit G. The examiner/engineer should include probable reserves associated with normal step-out drilling in the cost depletion computation.

B. Amount of Reserves to include: Most likely quantity expected to be recovered by the drilling of the normal step-outs. The examiner/engineer may determine the quantity by multiplying the quantity anticipated to be recovered from a successful well by the anticipated probability of success of the well. Taxpayers are likely to maintain estimates of this category of probable reserves.

C. The appropriate time to include the estimated quantity is the earlier of:

1. when the taxpayer classifies the reserves as probable, which may occur as early as the acquisition of the property;
2. when an authority for expenditure (AFE) to drill the step-out has been approved by the operator;
3. when an application to drill the well has been approved by the appropriate conservation agency; or
4. when significant expenditures related to drilling the step-out have occurred

.

Scenario No. Two: ***Reserves in formations that appear to be productive based on well log characteristic but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area.***

A. The existence of multiple geologic formations is a common occurrence in many geographic locations. Information gathered in the course of drilling and logging wells routinely identifies these "behind pipe" formations. The testing of behind pipe formations is a common part of the complete development of any oil and gas property. The formations are described as not being "analogous to producing or proved reservoirs in the area" , thus they would not be extensions of a known deposit. Whether they represent a new body or mass whose existence is indicated by geological surveys or other evidence to a high degree of probability is a question of fact. The ability to determine the vertical extent and petrophysical properties of these formations is usually evidence of such existence. The fact that the taxpayer describes the reserves contained in the formation as probable is further evidence of such existence. Accordingly the examiner/engineer should include probable reserves associated with these formations in the cost depletion computation.

B. Amount of Reserves to include: The quantity most likely to be recovered by the testing of the behind pipe formations. The examiner/engineer may determine this quantity by multiplying the amount anticipated to be recovered from a successful well completion by the anticipated probability of success of the completion. Taxpayers are likely to maintain estimates of this category of probable reserves.

C. For this type of activity, the appropriate time to include the estimated quantity is the earlier of: 1), 2), 3) or 4), as described above in Scenario No. One, part c).

Scenario No. Three: ***Incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate.***

A. This scenario is similar to SPE Factual Scenario Number Four in that, if certain steps are taken, the taxpayer is likely to recover some additional quantity beyond proved reserves from the assured portion of the deposit. This scenario differs in that it contemplates a change in the regulatory environment. The factual scenario does not indicate whether changes to statutory spacing are routinely approved by the appropriate conservation agency. There is some chance, albeit remote, that the taxpayer may never be able to recover the incremental reserves without a change in the statutory spacing. Examiners/engineers should not include these reserves until they have resolved these uncertainties for this type of activity.

B. Amount of Reserves to include: If the examiner/engineer succeeds in resolving the uncertainties, then the incremental reserves attributable to infill drilling quantity should be included in the cost depletion computation. Taxpayers are likely to maintain estimates of this category of probable reserves if they have substantial onshore holdings. Whether a well is an infill well is a question of fact.

C. Subject to the foregoing, for this type of activity, the appropriate time to include the estimated quantity is the earlier of: 1), 2), 3) or 4), as described above in Scenario No. One, part c).

Scenario No. Four: ***Reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application.***

A. In many instances companies implement improved recovery projects to recover some additional quantity beyond proved reserves from the assured portion of the deposit. The examiner/engineer should include probable reserves associated with these improved recovery projects in the cost depletion calculation

B. Amount of Reserves to include: The quantity most likely to be recovered by the improved recovery project. The examiner/engineer may determine this quantity by multiplying the quantity expected to be recovered by successful application of the improved recovery method by the probability of success of the project. Taxpayers are likely to maintain estimates of this category of probable reserves.

C. Whether a pilot or project is planned is a question of fact. It shall be considered to have occurred at the earlier of: 1), 2), 3) or 4), as described above in Scenario No. One, part c). Once the engineer has determined the pilot or project is planned, the probable reserves estimated should be included.

Scenario No. Five: ***Reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area.***

A. Separate fault blocks within the same geologic formation are common. While a separate fault block can sometimes be technically classified as a separate reservoir, it is not generally considered an entirely different and separate zone from the known producing zone. The type of well described by the SPE is reasonably analogous to an exploratory step-out. These are step-outs to a producing mineral deposit located at a considerable distance from the producing wells. See generally Rev. Rul. 77-136, 1977-1 CB 167. Therefore, IRS engineers consider a separate fault block as a "new body or mass" of the existing mineral deposit.

B. Whether the existence of a new body or mass is indicated by geological surveys or other evidence to a high degree of probability is a question of fact. The ability to map a separate fault block with enough certainty to plan a well location is usually evidence of such existence. The fact that the taxpayer describes the reserves contained in the fault block as probable is further evidence of such existence. Accordingly the examiner/engineer should include probable reserves associated with these formations in the cost depletion computation.

C. Amount of Reserves to include: The quantity most likely to be recovered by the testing of the behind pipe formations. The examiner/engineer may determine this quantity by multiplying the amount anticipated to be recovered from a successful well completion by the anticipated probability of success of the completion. Taxpayers are likely to maintain estimates of this category of probable reserves.

D. For this type of activity, the appropriate time to include the estimated quantity is the earlier of: 1), 2), 3) or 4), as described above in Scenario No. One, part c).

Scenario No. Six: ***Reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs.***

A. This is also similar to SPE Factual Scenario No. Four dealing with improved recovery methods because the taxpayer will have to take proactive steps and make expenditures to recover the reserves. However, the nature of the expenditure in this case is more closely related to operations than to development activity. If the described procedures are commercially employed in the industry, then the examiner/engineer may include the associated reserves if a reasonably prudent operator would pursue them. Whether these conditions have been met are questions of fact. As a result of these uncertainties, examiners/engineers should only include these probable reserves until after having resolved them.

B. Amount of Reserves to include: If the examiner/engineer succeeds in resolving the uncertainties then the quantity most likely to be recovered by the application of the procedure should be included in the cost depletion computation. The examiner/engineer may determine this quantity by multiplying the amount anticipated to be recovered from a successful procedure by the anticipated probability of success of the procedure. Taxpayers do not normally maintain estimates of this category of probable reserves.

C. For this type of activity, the appropriate time to include the estimated quantity is the earlier of: 1), 2), 3) or 4), as described above in Scenario No. One, part c).

Scenario No. Seven: ***Incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.***

A. This is similar to Factual Scenario No. Three because some additional quantity beyond proved reserves may be recovered from the assured portion of the deposit. This scenario differs in that, in some situations, the additional recovery may occur regardless of whether the taxpayer conducts additional development activities. An estimate of proved reserves made early in the life of a reservoir may be conservative since only limited performance data is available to predict future production levels. The examiner/engineer should include probable reserves associated with these assured deposits.

Exhibit 4.41.1-27
American Jobs Creation Act of 2004 Income Tax Provisions

The President signed into law the American Jobs Creation Act of 2004 (P.L. 108-357), on October 22, 2004. Income tax provisions affecting the domestic petroleum industry are summarized below:

A. **House Bill Section 302, Primary Code Section 40A - Biodiesel Income Tax Credit and revised Code Section 38(b) – General Business Credit.**

1. The Act creates Code Section 40A – Biodiesel Used as Fuel, providing an income tax credit reportable as a General Business Tax Credit for Biodiesel. Biodiesel is an alternative fuel produced from domestic renewable resources; for example, soybean oil or recycled cooking oils. Biodiesel contains no petroleum but can be blended with petroleum diesel into a bio-diesel blend. A common fuel blend would be 20 percent biodiesel / 80 percent petroleum diesel.
2. There are two parts to determining the credit. First, a credit of $.50/ gallon is allowed for each gallon of biodiesel used in the production of a qualified biodiesel blend that is sold by the taxpayer for use as a fuel or is used as a fuel by the producing taxpayer. Second, a credit of $.50/gallon is allowed for each gallon of biodiesel not in a mixture which is used by the taxpayer as a fuel or is sold at retail by the taxpayer directly to the fuel tank of the customer. The law raises the credit to $1.00/gallon if the biodiesel is agri-biodiesel (produced from first-use oils)
3. Taxpayers must secure certification for the biodiesel from the producer or importer to claim a credit. The biodiesel credit must be reduced by any excise tax credit claimed under Code Section 6426 or 6427(e). In general, if a credit is claimed and subsequently, any person separates the biodiesel or uses the mixture other than as a fuel there is a tax imposed on such person equal to the credit claimed.
4. The provision is effective for fuel sold or used after December 31, 2004 and before January 1, 2007.

B. **House Bill Section 338, Primary Code Section 179B – Expensing of Capital Costs Incurred in Complying with Environmental Protection Agency Sulfur Regulations.**

1. The Act creates Code Section 179B – Deduction for Capital Costs Incurred in Complying with Environmental Protection Agency Sulfur Regulations. The provision permits small business refiners (a taxpayer in the business of refining petroleum products who employs less than 1,500 employees and has less than 205,000 barrels per day (average) of total refining capacity) to claim an immediate deduction for up to 75 percent of the qualified costs paid or incurred when complying with EPA's highway diesel fuel sulfur control requirements. Qualified costs include expenditures for the construction of new process units or the dismantling and reconstruction of existing process units to be used in the production of low sulfur diesel fuel, associated adjacent or offsite equipment (including tankage, catalyst, and power supply), engineering, construction period interest, and sitework. The percentage of costs allowed is reduced for amounts in excess of 155,000 barrels a day of total refinery capacity.
2. The provision is effective for expenses incurred after December 31, 2002. As a result, examiners will need to be alert for potential claims that may be filed for tax years ending after this date.

C. **House Bill Section 339, Primary Code Section 45H – Credit for Production of Low Sulfur Diesel Fuel**

1. The Act creates Code Section 45H – Credit for Production of Low Sulfur Diesel Fuel. The provision provides a general business credit to small business refiners equal to 5-cents for each gallon of low-sulfur diesel fuel produced during the taxable year that complies with EPA sulfur control requirements. The total production credit claimed by the taxpayer cannot exceed 25 percent of the qualified cost incurred to comply with the EPA's highway diesel fuel sulfur control requirements. Basis in the property is reduced by the amount of credit claimed. To obtain the credit, the taxpayer will have to secure certification that the qualified costs will result in compliance with EPA regulations.
2. The provision is effective for expenses incurred after December 31, 2002. As a result, examiners will need to be alert for potential claims that may be filed for tax years ending after this date.

D. **House Bill Section 707, Primary Code Section, Primary Code Section 43 – Extension of Enhanced Oil Recovery Credit to Certain Alaska Facilities**

1. This provision amends Code Section 43(c)(1) (defining qualified enhanced oil recovery costs) by adding any amount paid or incurred during the taxable year to construct a gas treatment plant capable of processing two trillion Btu of Alaskan Natural Gas per day into a natural gas pipeline system. To qualify, the gas treatment plant must also produce carbon dioxide for re-injection into a producing oil or gas field.
2. This incentive provision is effective for property placed in service after December 31, 2004. Examiners should not see any effects of this provision in the near future.

Exhibit 4.41.1-28
Energy Policy Act of 2005 Income Tax Provisions

The President signed into law the Energy Policy Act of 2005 (HR 6) on August 8, 2005. Income tax provisions affecting the domestic petroleum industry are summarized below:

A. **House Bill Section 1323. Temporary expensing for equipment used in refining of liquid fuels - Primary Code Section 179C.**

    1. Under present law, petroleum refining assets are depreciated over a 10-year recovery period using the double declining balance method.
    2. The new provision provides a temporary election to expense 50 percent of the cost of qualified refinery investments. Any cost so treated is allowed as a deduction for the taxable year in which the qualified refinery property is placed in service. The remaining 50 percent is recovered under present law.
    3. Qualified refinery property includes assets, located in the United States, used in the refining of liquid fuels:
        - the original use commences with the taxpayer and is placed in ser-vice before January 1, 2012;
        - which meets all applicable environmental laws in effect on the date such portion was placed in service;
        - which increase the capacity of an existing refinery by at least 5 percent or increase the throughput of qualified fuels (as defined in section 45K(c)) by at least 25 percent.
        - with the respect to the construction of which there is a binding contract before January 1, 2008 (Note: in the case of self-constructed property, the construction of which began after June 14, 2005, and before January 1, 2008).
    4. The five percent capacity requirement refers to the output capacity of the refinery, as measured by the volume of finished products other than as-phalt and lube oil, rather than input capacity as measured by rated capacity.
    5. The expensing election is not available with respect to identifiable refinery property built solely to comply with Federally mandated projects or consent decrees. For example, a taxpayer may not elect to expense the cost of a scrubber, even if the scrubber is installed as part of a larger project, if the scrubber does not increase throughput or increased capacity to accommodate qualified fuels and is necessary for the refinery to comply with the Clean Air Act. This exclusion applies regardless of whether the mandate or consent decree addresses environmental concerns with respect to the refinery itself or the refined fuels.
    6. As a condition of eligibility for the expensing of equipment used in the refining of liquid fuels, the provision provides that a refinery must report to the IRS concerning its refinery operations, (e.g. production and output).
    7. Effective Date: The provision is effective for property placed in service after August 8, 2005, the original use of which begins with the taxpayer, provided the property was not subject to a binding contract for construction on or before June 14, 2005.

B. **House Bill Section 1325. Natural gas distribution lines treated as 15-year property - Primary Code Section 168 (e)(3)(E)(viii)**

    1. Gas distribution lines must be depreciated over 20 years under present law.
    2. The new legislation establishes a statutory 15-year recovery period and a class life of 35 years for distribution lines put in service after April 11, 2005. The provision amended Code Section 168(e)(3) to allow 15-year treatment to any natural gas distribution line the original use of which occurred after April 11, 2005 and before January 1, 2011. The provision does not apply to any property which the taxpayer or related party had entered into a binding contract for the construction thereof or self-constructed on or before April 11, 2005.
    3. Property not meeting the qualified criteria would continue to be depreciated over 20 years.
    4. Effective Date: Effective for property, the original use of which begins with the taxpayer after April 11, 2005, which is placed in service after April 11, 2005 and before January 1, 2011. The provision does not apply to property subject to a binding contract on or before April 11, 2005.

C. **House Bill Section 1326. Natural gas gathering lines treated as 7-year property - Primary Code Section 168(e)(3)(C)(iv).**

    1. The uncertainty regarding the appropriate recovery period of natural gas gathering lines has resulted in litigation between taxpayers and the Service.
    2. The new legislation establishes a statutory seven-year recovery period and a class life of 14 years for natural gas gathering lines. In addition, no adjustment will be made to the allowable amount of depreciation with respect to this property for purposes of computing a taxpayer's alternative minimum taxable income. The provision does not apply to any property which the taxpayer or related party had entered into a binding contract for the construction thereof on or before April 11, 2005, or in the case of self-constructed property, has stated construction on or before such date.
    3. A natural gas gathering line is defined to include any pipe, equipment, and appurtenance that is:
        A. determined to be a gathering line by the Federal Energy Regulatory Commission, or
        B. used to deliver natural gas from the wellhead or a common point to the point at which such gas first reaches:
            - a gas processing plant,
            - an interconnection with an interstate transmission line,
            - an interconnection with an intrastate transmission line,
            - a direct interconnection with a local distribution company, a gas storage facility, or an industrial consumer.
    4. Effective Date: Amendments made by this section shall apply to any natural gas gathering line the original use of which commences with the taxpayer and placed in service after April 11, 2005.

D. **House Bill Section 1328. Determination of small refiner exception to oil depletion deduction - Primary Code Section 613A(d)(4).**

1. Oil and gas producers are classified as either independent producers or integrated companies. A producer is an independent producer only if its refining and retail operations are relatively small. Under present law an independent producer may not have refining operations the runs from which exceeded 50,000 barrels on any day in the taxable year during which independent producer status is claimed. A refinery run is the volume of inputs of crude oil (excluding any product derived from the oil) into the refining stream.
2. The bill increases the current 50,000-barrel per day limitation to 75,000. In addition, the bill changes the refinery limitation claiming independent status from a limit based on actual production to a limit based on average daily production for the taxable year. Accordingly, the average daily refinery runs for the year may not exceed 75,000 barrels. For this purpose, the taxpayer calculates average daily refinery runs by dividing total refinery runs for the taxable year by the total number of days in the taxable year.
3. Effective Date: This provision is effective for taxable years ending after August 8, 2005.

E. **House Bill Section 1329. Amortization of geological and geophysical expenditures - Primary Code Section 167(h).**

1. Courts have held that geological and geophysical expenditures (G & G costs) are capital, and therefore are allocable to the cost of the property acquired or retained. Revenue Rulings 77-188 and 83-105 provided further guidance regarding the definition and proper tax treatment of G & G costs.
2. The new legislation allows geological and geophysical costs amounts in connection with oil and gas exploration in the United States to be amortized over two years. In the case of abandoned property, the remaining G & G basis may no longer be recovered in the year of abandonment of a property as all G & G basis is recovered over the two-year amortization period.
3. G & G costs incurred prior to August 8, 2005 are not covered in this provision. The provision also does not cover foreign G & G costs. These costs will continue to be capitalized and allocated to the property acquired or retained.
4. Effective Date: The provision is effective for geological and geophysical costs paid or incurred in taxable years beginning after August 8, 2005.

F. **House Bill Section 1346. Renewable Diesel - Primary Code Section 40A.**

1. The Act amends Code Section 40A (relating to biodiesel used as fuel) by extending its provisions to renewable diesel. It provides for an income tax credit reportable as a General Business Credit for renewable diesel used as a fuel in a trade or business, or sold at retail to another person and put in the fuel tank of that person's vehicle. Renewable diesel will be treated in the same manner as biodiesel except that:
   - the rate of credit with respect to renewable diesel will be $1.00 per gallon sold or used rather than 50 cents.
   - Subsections (b)(3) and (b)(5) in regard to agri-biodiesel shall not apply.
2. Biodiesel is an alternative to petroleum-based diesel fuel and is made from renewable resources such as vegetable oils or animal fats. Biodiesel contains no petroleum but can be blended with petroleum diesel into a biodiesel blend. A common fuel blend would be 20 percent biodiesel / 80 percent petroleum diesel.
3. The term "renewable diesel" means diesel fuel derived from biomass or any product thereof using a thermal depolymerization process which meets EPA and the American Society of Testing and Materials requirements.
4. The term '"biomass" means any organic material other than oil and natural gas (or any product thereof) and coal (including lignite) or any product thereof.
5. Thermal depolymerization (TDP) is a process for the reduction of complex organic materials (usually waste products of various sorts, often known as biomass) into light crude oil.
6. Effective Date: The effective date for this amendment shall apply with respect to fuel sold or used after December 31, 2005 and before December 31, 2008.

Exhibit 4.41.1-29
Tax Increase Prevention and Reconciliation Act (TIPRA) Income Tax Provisions

The President signed HR 4297, Tax Increase Prevention and Reconciliation Act of 2005 (P.L. 109-222), on May 17, 2006. The income tax provision affecting the domestic petroleum industry is summarized below:

A. **TIPRA Code Section 503: 5-Year Amortization on Geological and Geophysical Expenditures for Certain Major Integrated Oil Companies**

1. Primary Code Section dealing with this provision is 167(h). The provision extends the two-year amortization period for G & G costs to five years for certain major integrated oil companies. It applies only to integrated oil companies that have an average daily worldwide production of crude oil of at least 500,000 barrels for the taxable year, gross receipts in excess of $1 billion in the last taxable year ending during calendar year 2005, and an ownership interest in a crude oil refiner of 15 percent or more.

Exhibit 4.41.1-30
The Emergency Economic Stabilization Act of 2008

The provisions of the Emergency Economic Stabilization Act of 2008 affecting the domestic petroleum industry are summarized below:

A. **Sec. 209, Primary Code Section 179C - Election to Expense Certain Qualified Refinery Property**

1. The provision extends for two years (to property which is placed in service by the taxpayer before January 1, 2014, and the construction of which is subject to a written, binding construction contract entered into before January 1, 2010) the election to expense qualified refinery property and modifies the election to expense certain qualified refinery property with the inclusion of fuel derived from shale and tar sands.

Exhibit 4.41.1-31
History of IRC 40A, Biodiesel and Renewable Diesel Used as a Fuel

A brief history of Section 40A is provided below:

IRC 40A was enacted in 2004 to provide an income tax credit reportable as a General Business Tax Credit for Biodiesel used as fuel. This provision was initially effective for fuel sold or used after December 31, 2004 and before January 1, 2007.

In 2005, IRC 40A was amended by extending its provisions to include renewable diesel. The amendment provided for an income tax credit reportable as a General Business Credit for Renewable Diesel used as a fuel in a trade or business, or sold at retail to another person and put in the fuel tank of that person's vehicle. This amendment applied to fuel sold or used after December 31, 2005 and before December 31, 2008.

Originally, there were two parts to determine the credit:

- a credit of $.50 per gallon was allowed for each gallon of biodiesel used in the production of a qualified biodiesel blend that was sold by the taxpayer for use as a fuel or was used as a fuel by the producing taxpayer
- a credit of $.50/gallon was allowed for each gallon of biodiesel not in a mixture which was used by the taxpayer as a fuel or was sold at retail by the taxpayer directly to the fuel tank of the customer

In 2008, the law raised the credit to $1.00 per gallon for biodiesel, agri-biodiesel, renewable diesel, biodiesel included in a biodiesel mixture, agri-biodiesel included in a biodiesel mixture and renewable diesel included in a renewable diesel mixture. The Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010 retroactively extended the per-gallon incentives for biodiesel, agri-biodiesel, and renewable diesel for two additional years, through December 31, 2011.

Exhibit 4.41.1-32
LOGDP IDR No. 1 - Initial Request

Using Form 4564, make an initial request for these documents:

The request goes to xxx Drilling Company for the following information; reference tax year ending December 31, 20XX:
1. Detailed general ledger and all detailed subsidiary ledgers (in electronic format)
2. Chart of accounts
3. Book and tax trial balance
4. Year end journal entries and adjusting journal entries
5. Financial Statements – Income Statement and Balance Sheet (audited and/or unaudited)
6. Reconciliation of net income per financial statements to net income per books reported on Schedule M-1, Line 1
7. Copy of tax returns for inspection (prior and subsequent year returns)
8. Partnership Book Capital Account calculations
9. Partnership Basis calculations
10. Calculation of adjusted basis in property contributed
11. Proof of ownership by partnership in property contributed
12. Tax workpapers (including Schedule M's) used to compute income and expenses reported on the 20XX Form 1065. Include all of the separately stated items reported on Schedule K.
13. Trial Balance and any other financial statement(s) used to compute book and tax income and expenses for the 20XX tax year. Include all of the separately stated items reported on Schedule K

Exhibit 4.41.1-33
LOGDP IDR No. 2 - Partnership Formation

See items number 7, 8, and 11 in Exhibit 4.41.1-32.

Note:

An Excel, Word or Adobe-formatted response will be acceptable. Delivery media can be a CD.

Exhibit 4.41.1-34
LOGDP IDR No. 3 - Other Investments

Ask the taxpayer to provide a copy of a check, bank draft, wire transfer, or money order used to pay for the *Subscription Note* in xxx *Drilling Company* partnership. If there was more than one transaction, have the taxpayer provide copies of all instruments used. Copies of front and back of instrument should also be requested. All copies are to be retained in the case file. Attach a copy of the request with information provided.

Exhibit 4.41.1-35
LOGDP IDR No. 4 - Capital Accounts

The taxpayer should be requested to provide a copy of the following:

1. IRC 704(b) capital accounts, including annual adjustments and changes from formation through the most recent tax year
2. GAAP or other "book" basis capital accounts (if any), including annual adjustments and changes from inception through the most recent tax year
3. Schedule of all contributions to the partnership, including specific contribution dates, contribution amounts, itemization of contributed property, tax basis of contributed property on contribution date and fair market value of contributed property on contribution date
4. Schedule of all distributions from the partnership, including specific distribution dates, distribution amounts, itemization of distributed property, tax basis of distributed property on distribution date and fair market value of distributed property on distribution date
5. Description of any event(s) that led to an inside/outside basis differential, including date of event, agreements implementing the event(s), estimate of differential and how the differential is being allocated by the partnership

Note:

An Excel, Word or Adobe formatted response will be acceptable. Delivery media can be a CD.

Exhibit 4.41.1-36
LOGDP IDR No. 5 - Subscription Note

The taxpayer should be asked to provide a copy of Additional Collateral for Subscription Note agreement with xxx Drilling Company.

Exhibit 4.41.1-37
LOGDP IDR No. 6 - Partner Capital Accounts

The following information should be requested for each partner:

- documentation of distribution payments from the partnership's oil and gas income and interest income to the partners from the initial year of the partnership to date
- include allocation of gross distributions to note(s) principal, notes(s) interest, partners, and any other(s).
- include the identification of all payees from the partnership's gross distributions from initial year through current date

Exhibit 4.41.1-38
LOGDP IDR No. 7 - Investments in Oil and Gas Wells

Ask the company to provide any documents that address, discuss, or allude to the selection of investments or properties in any oil and gas well ventures, partnerships or other investment vehicles. This request covers, but is not limited to, studies, reports, and advice, whether recorded in writing or by means of electronic or other media including e-mail.

In addition, ask for any documents that refer to, address, discuss or allude to the value assigned to the turnkey drilling contract associated with the oil and gas well venture and to any decisions made with respect to the turnkey driller chosen to do the drilling, whether recorded in writing or by means of electronic or other media including e-mail.

Finally, provide any information related to any discussions related to the above requests, describing any such discussion, speech, presentation or other oral communication in the following terms: date, author or speaker, subject matter, reason for communication, result of communication, any other participants (by name, address, other contact information), and any follow-up communications.

Exhibit 4.41.1-39
LOGDP IDR No. 8 - Intangible Drilling Costs (IDC)

Request that xxx Drilling Company provide copies of the following:

1. all signed and dated division orders to mineral interests owned by xxx Drilling Company for which IDCs are claimed
2. any signed and dated agreements executed between xxx Drilling Company and the xxx Title Holding Corp. or any other similar company involved in the management of any minerals interest of the xxx Drilling Company
3. all signed and dated title documents of the prospects and mineral interests in wells held in the name of the xxx Title Holding Corporation or any other similar title holding company for the xxx Drilling Company
4. any signed and dated agreements executed between xxx Drilling Company and xxx Distribution Corporation or any other company that manages or maintains oil and gas production records or makes royalty payments for xxx Drilling Company on a regular basis
5. all signed and dated lease or farm-out agreements executed between xxx Drilling Company and xxx Exploration Company or any other similar drilling or exploration company conducting business in prospects and farm-outs
6. signed and dated drilling programs prepared by xxx Exploration Company or any turnkey drilling company for any prospects or wells held by xxx Drilling Company
7. any signed and dated lease and assignment agreements executed between xxx Drilling Company and any turnkey drilling company or any other company
8. contact names, addresses, and telephone numbers for those representatives of any turnkey drilling company that managed the drilling of wells for xxx Drilling Company
9. contact names, addresses, and telephone numbers for those representatives of the xxx Title Holding Corp. or any other title holding company for any mineral interests for the xxx Drilling Company
10. contact names, addresses, and telephone numbers for those representatives of xxx Exploration Company or any other operating company that conveyed prospects or farm-outs to the xxx Drilling Company

Request additional documentation:

1. contact names, addresses, and telephone numbers for those representatives of xxx Distribution or any other company that arranged for or managed oil and gas production records and royalty payments for xxx Drilling Company
2. a listing in hardcopy (and in electronic form, if available) of all wells drilled for which IDC was claimed. For each well, the listing should include the IDC dollar ($) amount which reconciles to the tax return for the tax year in question, well name, API well number, drilling total depth, location (including county, state, field name, lease name, offshore well block), OCS lease number and drilling permit number issued by the appropriate oil and gas regulatory agency, and current or final status (e.g., producer, dry hole, etc.). In addition to the above items for each well, the listing should include the following dates: the well spud date, the date for end of drilling activity, and the date for end of well completion activity, the date well was tested for production or the date well was re-completed and tested for production
3. for each well, provide the listing of the designated operator, the names of the drilling and turnkey contractors, percentage of working interest owned by the partnership (and each partner), and the date at which the partnership (and each partner) received the working interest in the well
4. signed and dated copy of the drilling permit obtained from the state or federal agency for each well for which IDC's or dry hole cost was claimed
5. signed and dated copy of the subsequent well completion report from the state or federal agency for each well for which IDCs or dry hole cost was claimed
6. copy of the signed and dated subsequent plugging and abandonment report from the state or federal agency for each well for which IDC's or dry hole cost was claimed
7. for each well, copy of the ledger account(s) in which the amounts of IDC's were recorded, and a breakdown of the components of the IDC dollar ($) amounts that reconcile to the claims for IDC amounts

8. pertinent tax work papers reconciling the IDC dollar ($) amounts for each well identified above, and reported on the tax return for the year in question

Exhibit 4.41.1-40
LOGDP IDR No. 9 - Turnkey Driller IDC

Request from xxx Drilling Company answers to these questions:

A. Did any IDC costs represent prepaid expenses pursuant to a contractual arrangement? If yes, please identify all wells associated with such IDC costs and provide a copy of such contract.
B. Did the Turnkey Driller actually drill the well? If no, please provide the name of the drilling contractor that the operator used to actually drill the wells and the rig used to drill the well.
C. Did the Turnkey driller cause the well to be drilled by another party? If yes, please provide the contract between the Turnkey driller and the third party.
D. Does the Turnkey Driller actually own drilling rigs and maintain drilling crews? If yes, please identify the rig used, type, depth rating, and number of employees working for the turnkey drilling contractor.
E. Is the Turnkey Driller actively engaged in the drilling business? If yes, please identify the commercial publication listing him as a drilling contractor in the oil and gas industry.
F. Were any IDC's for dry hole costs associated with a partial abandonment of a well or non-productive section of a well (e.g. shallow section of well is producing and deduction taken for deeper non-productive portion or side track)

Exhibit 4.41.1-41
Tax Shelter Partner Listing

PARTNER NAME	TOTAL P/S PER PARTNER	Statute Date	XYZ DRILLING COMPANY	ABC DRILLING COMPANY	XXX DRILLING COMPANY	ZZZ DRILLING COMPANY	123 DRILLING COMPANY	AAA DRILLING COMPANY	NEW DRILLING COMPANY
TOTAL PARTNERS PER P/S			3	3	6	6	4	5	5
Partner 1	2	12/31/20xx	1		1				
Partner 2	2	12/31/20xx	1					1	
Partner 3	2	12/31/20xx	1					1	
Partner X	2	12/31/20xx		1		1			
Partner Y	1	12/31/20xx		1					
Partner Z	2	12/31/20xx		1					1
Partner AA	1	12/31/20xx			1				
Partner AB	1	12/31/20xx			1				
Partner AC	2	12/31/20xx			1			1	
Partner 4	2	12/31/20xx				1		1	
Partner 5	1	12/31/20xx				1			
Partner 6	1	12/31/20xx				1			
Partner AAA	1	12/31/20xx				1			
Partner AAB	1	12/31/20xx				1			
Partner AAC	1	12/31/20xx					1		
Partner 7	1	12/31/20xx					1		
Partner 8	2	12/31/20xx			1		1		
Partner 9	3	12/31/20xx			1		1	1	
Partner ABC	1	12/31/20xx							1
Partner 10	1	12/31/20xx							1
Partner 11	1	12/31/20xx							1
Partner 12	1	12/31/20xx							1

Exhibit 4.41.1-42
Regulatory Agency Filings with Respect to Refinery Volumes

Although there is no standard system of accounting employed across all oil refineries, they are subject to numerous regulatory rules and reporting requirements associated with hazardous chemicals and inventories. Some of the primary ones include:

Mandating Agency or Statute	Pertinent Rule or Requirement
EPA Risk Management	reporting of hazardous materials; see 40 CFR part 68
OSHA Process Safety Management	sets standards of Highly Hazardous Chemicals; see 29 CFR 1910.119
Superfund Amendments and Reauthorization Act Title III ("SARA Title III"	implements the Emergency Planning and Community Right to Know Act; see 42 USC §116
Emergency Planning and Community Right to Know Act (EPCRA)	Tier II reporting requirements; see 42 USC §116, 11022 and 40 CFR parts 311 and 312
Energy Information Administration Form	EIA-810 "Monthly Refining Report" ; mandatory pursuant to Section 13(b) of the Federal Energy Administration Act of 1974 (PL 93-275) which must be completed by the operators of all operating and idle petroleum refineries located in the 50 states, DC, and U.S. possessions
State Emergency Response Commission (SERC)	SERC or Local Emergency Planning Commission (LEPC), local fire department rules
Foreign Trade Zone (FTZ) -- if refinery is located in one	FTZ reporting rules and inventory control, record-keeping (ICRS); see 48 Stat. 998-1003; 19 CFR §§146.6(b)(4) and 146.21(b) and Part 146 Subpart H Petroleum Refineries in Foreign-Trade Subzones
Bureau of Customs and Border Protection (CBP)	repository of admittance and entry documents for FTZ zones

Most refineries operating in the U.S. are located in Foreign Trade Zones and Subzones. Operators must maintain an inventory and recordkeeping system of the zone in accordance with Foreign Trade Zone regulations. See 19 CFR Part 146 (19 CFR 113.73(a)(2), 146.4(d)). Regulations concerning protection of the revenue are approved by the Secretary of the Treasury. See 19 USC 81p, regulations established in 19 CFR Part 146. All merchandise admitted to the zone is recorded in a receiving report or document using a zone lot number (ZLN) or unique identifying number (UIN). The unique identifier specified in 19 CFR Part 146, Subpart B. refers to the unique numerals, letters or other characters used to identify a specific inventory category, including fungible merchandise. See Foreign Trade Zone Manual (FTZM), section 7.8(5)(b), 2003 edition.

A zone operator may request approval from Customs Headquarters for an authorized inventory method in lieu of the zone lot number system. FIFO is an approved method under Customs Service Decision 81-61 for Customs, and an operator need not request approval for the zone if the inventory method is already approved for general use by Customs Headquarters. Merchandise may be identified by an inventory method authorized by Customs, which is consistently applied, such as FIFO and using a unique identifier. See 19 CFR §146.23(a)(2). Aside from FIFO, the FTZA specifically authorizes a unique inventory method called "Industry Standards of Potential Production on a Practical Operating Basis" as verified and adopted by the Secretary of the Treasury (known as "producibility") as an inventory method for feedstocks for petroleum refineries operating in zones. See 19 USC §81c (d), sections 7.8(c)(5), and 11.6(j) of FTZM 2003 edition. Specific regulations for petroleum refineries are set forth in 19 CFR 146 Subchapter H - Petroleum Refineries in Foreign Trade Subzones.

The refinery producibility standards are set forth in Treasury Decision 66-16. Refineries in U.S. Foreign Trade Zones use this inventory method for attributing final products to feedstocks (authorized by 19 USC § 81(d) FTZA and 19 CFR §146.95(a)(1). Annual reconciliations are required and contain the following information:

- zone status of merchandise processed;
- item description for each unique identifier number (UIN)
- quantity on hand at beginning of year;
- cumulative receipts and transfers (by UIN); and
- quantity on hand at year-end, pursuant to 19 CFR §146.25(b)

Within the acceptable inventory tracking systems is the concept of "work in progress" as a "black box" that Customs is not allowed to penetrate. This means that if an operator can demonstrate raw material balance, inputs to production, finished products balance and some form of correlation between the three, this is satisfactory to Customs. "Customs shall accept the operator's operating conventions to the extent that the operator demonstrates that it actually uses these conventions in its refinery operations. Whatever conventions are elected by the operator, they must be used consistently in order to be acceptable to Customs ." See 19 CFR §146.95(b) Refinery operating record.

Because of the black box concept, actual inventory work-in-progress amounts are not reported to Customs. The operator need only demonstrate to Customs that the attribution and yield accounting within the refinery is reflective of actual operating conventions. The inventory attribution system in Treasury Decision 66-16 is not meant to be an inventory control system to reflect actual feedstocks at any given time. It is a method to account for import duties owed on privileged foreign feedstocks.

Exhibit 4.41.1-43
MACRS Asset Classes Commonly Used in the Petroleum Industry

			Recovery Period (in years)	
Asset Class	**Description of Assets Included**	**Class Life (in years)**	**General Depreciation System - IRC 168(a)**	**Alternative Depreciation System - IRC 168(g)**
00.3	**Land Improvements**: Includes improvements directly to or added to land, whether such improvements are IRC 1245 property or IRC 1250 property, provided such improvements are depreciable. Examples of such assets might include sidewalks, roads, canals, waterways, drainage facilities, sewers (not including municipal sewers in Class 51), wharves and docks, bridges, fences, landscaping, shrubbery, or radio and television transmitting towers. Does not include land improvements that are explicitly included in any other class, and buildings and structural components as defined in IRC 1.48-1(e) of the regulations. Excludes public utility initial clearing and grading land improvements as specified in Rev. Rul. 72-403, 1972-2 C.B. 102.	20	15	20
13.0	**Offshore Drilling**: Includes assets used in offshore drilling for oil and gas such as floating, self-propelled and other drilling vessels, barges, platforms, and drilling equipment and support vessels such as tenders, barges, towboats and crewboats. Excludes oil and gas production assets.	7.5	5	7.5
13.1	**Drilling of Oil and Gas Wells**: Includes assets used in the drilling of onshore oil and gas wells and the provision of geophysical and other exploration services; and the provision of such oil and gas field services as chemical treatment, plugging and abandoning of wells and cementing or perforating well casings. Does not include assets used in the performance of any of these activities and services by integrated petroleum and natural gas producers for their own account.	6	5	6
13.2	**Exploration for and Production of Petroleum and Natural Gas Deposits**: Includes assets used by petroleum and natural gas producers for drilling of wells and production of petroleum and natural gas, including gathering pipelines and related storage facilities. Also includes petroleum and natural gas offshore transportation facilities used by producers and others consisting of platforms (other than drilling platforms classified in Class 13.0), compression or pumping equipment, and gathering and transmission lines to the first onshore transshipment facility. The assets used in the first onshore transshipment facility are also included and consist of separation equipment (used for separation of natural gas, liquids, and solids), compression or pumping equipment (other than equipment classified in Class 49.23), and liquid holding or storage facilities (other than those classified in Class 49.25). Does not include support vessels.	14	7	14
13.3	**Petroleum Refining**: Includes assets used for the distillation, fractionation, and catalytic cracking of crude petroleum into gasoline and its other components.	16	10	16
15.0	**Construction**: Includes assets used in construction by general building, special trade, heavy and marine construction contractors, operative and investment builders, real estate subdividers and developers, and others except railroads.	6	5	6
28.0	**Manufacture of Chemicals and Allied Products**: Includes assets used to manufacture basic organic and inorganic chemicals; chemical products to be used in further manufacture, such as synthetic fibers and plastics materials; and finished chemical products. Includes assets used to further process man-made fibers, to manufacture plastic film, and to manufacture nonwoven fabrics, when such assets are located in the same plant in an integrated operation with chemical products producing assets. Also includes assets used to manufacture photographic supplies, such as film, photographic paper, sensitized photographic paper, and developing chemicals. Includes all land improvements associated with plant site or production processes, such as effluent ponds and canals, provided such land improvements are depreciable but does not include buildings and structural components as defined in Treas. Reg. 1.48-1(e). Does not include assets used in the manufacture of finished rubber and plastic products or in the production of natural gas products, butane, propane, and byproducts of natural gas production plants.	9.5	5	9.5
46.0	**Pipeline Transportation**: Includes assets used in the private, commercial, and contract carrying of petroleum, gas and other products by means of pipes and conveyors. The trunk lines and related storage facilities of integrated petroleum and natural gas producers are included in this class. Excludes initial clearing and grading land improvements as specified in Rev. Rul. 72-403, 1972-2 C.B. 102, but includes all other related land improvements.	22	15	22
49.21	**Gas Utility Distribution Facilities**: Includes gas water heaters and gas conversion equipment installed by utility on customers premises on a rental basis.	35	20	35
49.221	**Gas Utility Manufactured Gas Production Plants**: Includes assets used in the manufacture of gas having chemical and/or physical properties which do not permit complete interchangeability with domestic natural gas. Does not include gas producing systems and related systems used in waste reduction and resource recovery plants which are elsewhere classified.	30	20	30
49.222	**Gas Utility Substitute Natural Gas (SNG) Production Plant (naphtha or lighter hydrocarbon feedstocks)**: Includes assets used in the catalytic conversion of feedstocks or naphtha or lighter hydrocarbons to a gaseous fuel which is completely interchangeable with domestic natural gas.	14	7	14
49.23	**Natural Gas Production Plant**.	14	7	14
49.24	**Gas Utility Trunk Pipelines and Related Storage Facilities**: Excluding initial clearing and grading land improvements as specified in Rev. Rul. 72-403.	22	15	22
49.25	**Liquefied Natural Gas Plant**: Includes assets used in the liquefaction, storage, and regasification of natural gas including loading and unloading connections, instrumentation equipment and controls, pumps, vaporizers and odorizers, tanks, and related land improvements. Also includes pipeline interconnections with gas transmission lines and distribution systems and marine terminal facilities.	22	15	22

			Recovery Period (in years)	
Asset Class	**Description of Assets Included**	**Class Life (in years)**	**General Depreciation System - IRC 168(a)**	**Alternative Depreciation System - IRC 168(g)**
57.0	**Distributive Trades and Services**: Includes assets used in wholesale and retail trade, and personal and professional services. Includes IRC 1245 assets used in marketing petroleum and petroleum products.	9	5	9
57.1	**Distributive Trades and Services-Billboard, Service Station Buildings and Petroleum Marketing Land Improvements:** Includes IRC 1250 assets, including service station buildings and depreciable land improvements, whether IRC 1245 property or IRC 1250 property, used in the marketing of petroleum and petroleum products, but not including any of these facilities related to petroleum and natural gas trunk pipelines. Includes car wash buildings and related land improvements. Includes billboards, whether such assets are IRC 1245 property or IRC 1250 property. Excludes all other land improvements, buildings and structural components as defined in Treas. Reg. 1.48-1(e).	20	15	20
	Per IRC 168(e)(3)(C) 7- year property includes -- (iv) any natural gas gathering line the original use of which commences with the taxpayer after April 11, 2005.	14	7	14
	IRC 168(e)(3)(E) 15-year property includes – (iii) a retail motor fuels outlet (whether or not food or other convenience items are sold at the outlet). See Rev. Rul. 97-29 or Pub 946 for the applicable definition of "retail motor fuels outlet" .	20	15	20

Exhibit 4.41.1-44
Glossary of Oil and Gas Industry Terms

Term	Definition
Abandonment Costs	Once production from an oil or gas well becomes unprofitable the well is abandoned. Usually, before a well is abandoned, some of the casing is removed and salvaged and one or more cement plugs are placed in the borehole. In many states, abandonment must be approved and approved by the official regulatory agency.
Absorption	The physical assimilation of one substance into another; the extraction of one or more fluids from an atmosphere or mixture of gases or liquids by the substance of a sorbent material with which the atmosphere, gases, or liquids come in contact.
Acid Treating	A process for removing undesirable (chemically active) constituents of oil by contacting with sulfuric acid.
Acidize	To pump acid into a well to remove debris in the perforations and dissolve certain materials in the formation near the wellbore in order to improve the flow of oil and gas.
Acquisition Well	A well drilled in return for a mineral interest in a property.
Acreage Selection Option	A provision in a leasing agreement giving the grantee the right to select certain acreage, for the purpose of additional exploration or development, out of the total acreage explored.
Active Income/Losses	Income/losses generated from an activity (trade or business) in which the taxpayer materially participates on a regular, continuous, and substantial basis.
Actuals	The physical, cash, or spot market commodities, distinguished from commodity futures.
Additive	A chemical or other product that enhances certain characteristics or gives them other desirable properties (e.g., adding methyl tertiary butyl ether to gasoline to improve its octane).
Adsorption	The adhesion of molecules of gases or liquids to the surface of other bodies, usually solids, resulting in a relatively high concentration of the gas or solution at the point of contact.
Advance Royalty	An advance payment made by the owner of an operating interest to the royalty owner for a specific number of units of minerals regardless of whether oil or gas was extracted during the year. The payment is recoupable out of the future production.
AFE	Authorization for expenditures. It is a form used during the planning process for a well about to be drilled. It can also be used for other projects. The form includes an estimate of costs to be incurred in the intangible drilling costs (IDC) catetory and in the tangible equipment category. Costs are shown in total with accompanying breakdowns. The form represents a budget for the project against which actual expenditures are compared.
AFRA	Average Freight Rate Assessments. A measure of the cost of sea transportation incurred on crude oil and products.
Alkali	Any substance, such as ammonia, or caustic soda, containing a reactive hydroxide or oxide that forms a salt when reacted to neutralize acid. It is often referred to as a base.
Alkylate	Product obtained in the alkylation process. Chemically, it is a complex branched molecule of the paraffinic series. The alkylate will be of higher octane than the feedstock.
Allowables	Most oil producing states have regulatory agencies that are concerned with the conservation of natural resources, including extractive minerals. In regard to oil and gas, efficient extraction rates promote conservation of the resource. State regulatory agencies determine the amount of production that will be allowed within a given period. This may be stated in terms of producing days, or as a percentage of full production, and is usually figured on the basis of the individual well. The term "allowable production" has been shortened to allowables. These allowables are based on the market demand for oil or gas and the most efficient rates of production for the particular fields.
Anhydrous	Lacking water, dry, including loss of water in crystallization.
Anticipatory Hedge	A hedge involving the purchase and sale of futures contracts or forward commitments to protect against adverse changes in prices for anticipated transactions. For example, an oil producer may sell a futures contract to fix the price of future production.
Antioxidants	Chemicals added to gasoline, lubricating oils, waxes, and other products to inhibit oxidation, and thus, degradation of fuel quality.
API	American Petroleum Institute.
API Gravity	See Gravity.
Arbitrage	The simultaneous purchase and sale of identical or substantially similar securities or commodities in different markets in order to benefit from a price differential.
Area of Interest	The original project area of a geological or geophysical survey is subdivided into smaller projects, or "Areas of Interest" , to conduct more intensive exploration in order to determine whether to acquire or retain certain mineral interests within or adjacent to the area of interest. See Geological and Geophysical for treatment of the costs.
Aromatics	Hydrocarbons derived from or characterized by the presence of the benzene ring. Some of this large class of cyclic and polycyclic organic compounds are odorous. Most burn with a sooty flame but have high octane numbers.
Ash	Inorganic residue remaining after ignition of combustible substances, measured by standard prescribed methods.
Ask	The price at which a commodity or security is offered for sale.
Assignment of Lease	A legal document transferring all or a portion of the operating rights of a lease.
Balancing	The process by which persons having an interest in production adjust their take therefrom to ensure each interest holder receives his or her proportionate part of production.
Barrel (BBL)	A standard measure of volume for crude oil and liquid petroleum products. A barrel is 42 U.S. gallons.
Basic Sediment and Water (BS&W)	A combination of impurities and water that is often produced with crude oil. BS&W is heavier than oil and will settle to the bottom of a tank of produced oil.
Benzene Ring	A six-member ring of carbon atoms, joined together by alternate single and double bonds. A benzene ring is present in all aromatics.
Bid	An offer to buy securities or a specific quantity of a commodity.
Biodiesel	A fuel typically made from soybean, canola, or other vegetable oils; animal fats; and recycled grease. It can serve as a substitute for petroleum-derived diesel or distillate fuel.
Bit	A drilling tool that cuts a hole.
Bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulfur compounds and that, in its natural occurring viscous state, is not recoverable at a commercial rate through a well. Typically used to refer to the hydrocarbon material in Canadian oil sands.
Black Oil	A general term used to describe liquid crude oil or heavy fuel oils. (Also referred to as "dirty cargoes" .) It is necessary to clean a tank car, storage tank, etc., that has contained black oils before it can be used for clean fuels.
Blending	(1) Mixing refinery products to suit market conditions. (2) Mixing on-specification fuel with off-specification fuel to bring the latter within use limits (reclamation).
Blow Out	A sudden, violent expulsions of oil and gas from a drilling well, followed by an uncontrolled flow from the well.

Term	Definition
BOE	Barrel of Oil Equivalent. A unit which expresses volumes of natural gas in terms of equivalent barrels of oil. IRC 613A(c)(4) and IRC 776(b)(3)(B) equate 6 MCF of natural gas to 1 barrel of oil.
Boiling Points	Initial boiling point is the temperature at which a liquid begins to be converted into a vapor. End boiling point is the temperature at which a liquid becomes completely vaporized. These two points are called cut points or fractions.
Bonus	The consideration received by the lessor or sublessor upon execution of an oil or gas lease.
Bonus Exclusion Rule	A rule that is designed to prevent a percentage depletion deduction, by both a lessor and lessee, on the same production. The rule provides that the taxpayer (lessee) who paid the bonus must exclude an allocable part of the bonus when computing "gross income" and "taxable income" from the property for purposes of determining the amount of the percentage depletion allowance. See Treas. Reg. section 1.613–2(c)(5)(ii), Rev. Rul. 79–73, 1979–1 C.B. 218, and Rev. Rul. 81–266, 1981–2 C.B. 139.
BOP	Blow Out Preventer. A large device located on top of a well that helps the drilling crew control a blow out or a pending blow out. Within the BOP is a series of valves, "rams" and "shears" that are designed close in specific situations.
Bottom-Hole	The lowest or deepest part of a well.
Bottom-Hole Contributions	Money or property given to an operator for use in drilling a well on property in which the payor has no property interest. The contribution is payable when the well reaches a predetermined depth, regardless of whether the well is productive or nonproductive. Usually, the payor receives geological data from the well.
Bottoms	In a distilling operation, that portion of the charge remaining in the still at the end of the run; i.e. that portion that does not vaporize called the residuals.
British Thermal Unit (BTU)	A measure of the amount of heat required to raise the temperature of 1 lb. of water 1° F.
Bulk Petroleum Products	Large volume of products normally transported by pipeline, rail tank, tank truck, barge or tanker.
Butane	An inflammatory gaseous hydrocarbon belonging to the methane series. It is gaseous at ordinary atmospheric conditions, but it is readily convertible to a liquid state.
C.I.F.	Cost, insurance, and freight (included in the price quoted). Any price stated C.I.F. is not gross depletable income because it includes insurance and freight.
Carbon Dioxide	An inert, noncombustible, odorless gas at normal temperature and pressure conditions. This gas has become a valuable resource employed in tertiary oil recovery methods.
Carried Interest	An arrangement where one co-owner of an operating interest incurs an obligation to pay all of the costs to develop and operate a mineral property, in exchange for the right to recoup this investment out of the proceeds of the first production from the property. After the investment is repaid, any subsequent production is split between the co-owners. The co-owners that are not obligated to pay for the development and operation hold a carried interest in the mineral property until the carrying party's investment is repaid.
Carved-Out Drill Site	A site for drilling a single well. It is "carved out" of a large tract and is transferred in total, or in part, to an operator or operators who will drill a well on it. It is generally the smallest sized tract on which the state regulatory body will allow a well to be drilled. For example, the carved out drill site may be 40 acres out of a 160-acre tract owned.
Carved-Out Oil or Gas Payment	A payment in oil or gas assigned by the owner of an interest in oil and gas. The payment is to be paid out of a fractional part of the owner's interest and will run for a period less than the life of the interest from which it was carved. Except for oil or gas production payments pledged for development, production payments are treated as loans.
Cash Price	Price in the cash market for actual or spot commodities with delivery through customary market channels.
Casing	Steel pipe placed in an oil or gas well. Its main function is to prevent the well walls from caving in and to protect the well bore and in-hole equipment. It also prevents oil from migrating into other porous zones.
Casing Point	The point in time in the drilling of a well when drilling is completed and the operator must decide to set casing and attempt to complete the well or plug it as a dry hole.
Casinghead Gas	Gas produced from an oil well. The casinghead gas is usually taken off at a gas/oil separator.
Catalyst	A substance that affects, provokes, or accelerates chemical reactions without being altered itself.
Catalytic Cracking	A method of cracking in which a catalyst is employed to bring about the desired chemical reaction.
Cementing	The process by which a slurry of cement and water is placed in the well bore between the casing and the walls of the hole or another string of casing. The cement is forced behind the casing from the bottom up. It holds the casing in place and seals the producing zone off from other upper (possible "thief") zones.
CFE	Cubic foot (of gas) equivalent. The unit often used for gas production, when barrels of condensate or other liquids are converted to cubic feet of natural gas. Analogous to BOE.
Charge	In the context of refining, the amount of feedstock which is fed into a processing unit.
Checkerboard Acreage	Mineral interest situated in a checkerboard pattern. Generally, this is done to spread the risk, or to make sure the producer will have some ownership if production is found.
Christmas Tree	An assembly of valves mounted on the casinghead through which oil and gas is produced. The christmas tree also contains valves for testing the well and for shutting it down if necessary. A subsea production system is similar to a conventional land tree except it is assembled complete for remote installation on the sea floor with or without diver assistance. The marine (“wet”) tree is installed from the drilling unit and anchored to foundation legs implanted in the ocean floor. The tree is then latched mechanically or hydraulically to the casinghead by remote control.
Coke	See Petroleum Coke.
Common Carrier	Any cargo transportation system that may be accessed by any appropriate shipper and all shippers are charged the same rate schedule. Many pipelines are common carriers.
Complete Payout	Complete payout occurs when the owner of the operating interest completely recovers the cost of drilling, equipping, and operating a well from proceeds of production of that well. The term is commonly used in reference to carried interest arrangements.
Completion Cost	Costs incurred, after the drilling of a well reaches total depth, in preparing the well for production; i.e., running and cementing the production casing, replacing drilling mud with completion fluid, perforating the casing, fracturing or acidizing the reservoir, installing the tubing and christmas tree, and swabbing the well.
Concession	The operating right to explore for and develop oil and gas in a specific area in consideration for a share of production in kind (equity oil).
Condensate	A light hydrocarbon liquid that is in a gaseous state in the reservoir, but becomes liquid when temperature and pressure are reduced.
Contiguous Property	Tracts that have a common boundary. Tracts that touch only at a common corner are not contiguous.
Continuing Interest	An economic interest in an oil or gas property that entitles the holder to receive all or a portion of the oil and/or gas produced, or the proceeds from the sale of such oil and/or gas for the entire life of the property. A continuing interest is contrasted to a production payment, which must, by definition, have an economic life of shorter duration than the economic life of one or more of the properties it burdens.
Contract Price	See Term Price.
COPAS	Council of Petroleum Accountants Society of North America.
Core	A solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation.
Cracking	The refinery process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules.
Crude Oil	A mixture of hydrocarbons that exist in a liquid phase in natural underground reservoirs and which remains liquid at atmospheric pressure after passing through surface separating facilities. In the United States, crude oils are classified as paraffin base, naphthene base, asphalt base, or mixed base. The properties of the residuum left from nondestructive distillation determine the appropriate classification.
Cushion Gas	The gas required in a reservoir to maintain reservoir pressure.
Cut	See Fraction.
Damage Payments	Payments made to the landowner by the oil or gas operator for damages to the surface, to growing crops, to streams, or other assets of the landowner.
Day Rate	An agreed rate per day to drill a well. This rate does not include additional cost for such items as drilling mud, site preparation, fuel, etc.
Decline Rate	The rate at which the flow of oil or gas from a field falls as production proceeds.
Deferred Bonus	A lease bonus payable in installments over a period of years. The deferred bonus is distinguishable from delay rentals because the deferred bonus payments are due even if the lease is terminated, while delay rentals are discontinued with the termination of the lease or when development activities begin.
Delay Rental	Money payable to the lessor by the lessee for the privilege of deferring drilling operations or commencement of production during the primary term of the lease.
Delineation Well	A well drilled to determine the boundaries of the field.

Term	Definition
Depletion	Treas. Regs.1.611 through 1.613A provide taxpayers with an annual deduction in respect of an oil, gas or geothermal property. Taxpayers are allowed the greater of cost depletion or percentage depletion with respect to each mineral property. The cost depletion allowance is a ratable recovery of basis as mineral is produced. Percentage depletion is an allowance based on a percentage (15 percent for oil and gas properties) of the taxpayer's gross income from the sale of oil and gas, but limited to 100 percent of the net income of the property. See Gross Income from the Property.
Derrick	A tower used in the drilling of oil and gas wells as support for the equipment lowered into the well.
Development Well	A well drilled for production in an area where proven reserves are located.
Discovery Well	The first oil or gas well drilled in a field revealing oil or gas deposits.
Disposal Well	A well used for disposal of saltwater.
Distillation	This generally refers to vaporization processes in which the vapor evolved is recovered by condensation. Thus, a separation is effected between volatile fractions that vaporize at a specific temperature and those that do not.
Division Order	A contract between all of the owners of an oil and gas property and the company purchasing production from the property. The contract sets forth the interest of each owner and serves as the basis on which the purchasing company pays each co-owner their respective share of the proceeds of the oil and gas purchased.
DOE	U.S. Department of Energy.
Drill Site	The location at which a well is to be drilled. The "site" contains sufficient leasehold working interest acres to permit the drilling of one well.
Drilling Mud	A special mixture of clay, water, and chemical additive circulated through the well bore during drilling. Its functions are to cool the drill bit, lubricate the drill pipe, protect against blowouts by holding back subsurface pressure, carry rock cuttings to the surface, and deposit mud cake on the wall of the hole to prevent the bore hole from collapsing.
Drilling rig	Generally the actual equipment package used to drill a well, such as the derrick, draw works, rotary table, drill string, power system and mud system. May be permanently or temporarily installed on an offshore drilling platform. Permanently integrated into a MODU.
Dry Gas	Natural gas composed of vapors with only small amounts of dissolved liquid. Dry gas generally is composed of almost 100% methane (CH_4).
Dry-Hole	A well drilled for the production of oil and gas that either did not penetrate any productive reservoirs, or only penetrated reservoirs that do not yield commercial quantities of oil or gas after the well is completed. See Nonproductive Well.
Dry-Hole Contributions (DHC)	Money or property paid by property owners to another operator drilling a well on property in which the payors have no property interest. Such contributions are payable only in the event the well reaches an agreed depth and is found to be dry. Usually the payor receives geological data for this payment. DHC's are a type of bottom-hole contribution.
Dual Capacity Taxpayer	One who is subject to a foreign tax levy, but who also receives a specific economic benefit (directly or indirectly) from that foreign country. In the oil and gas context, the most frequent concern is whether payments made by companies to the sovereign are income taxes or royalties.
E10	Motor gasoline with up to 10 percent ethanol. Widely mandated by the EPA, especially in urban areas.
E85	Motor gasoline containing 85 percent ethanol. Only available in certain regions of the U.S.
Economic Interest	In order to be eligible to obtain income tax benefits, such as depletion, a taxpayer must possess a legal or equitable ownership interest in the minerals in place and receive income from the extraction and sale of such minerals. The definition of "economic interest" found in Treas. Reg. Section 1.611–1(b) is as follows: An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in mineral in place or standing timber and secures, by any form of legal relationship, income derived from the extraction of the mineral or severance of the timber, to which he must look for a return of his capital.
EIA	Energy Information Administration. A branch of the U.S. Department of Energy that collects, analyzes, and disseminates information and reports about many types of energy and fuels.
Enhanced Oil Recovery (EOR)	Sophisticated recovery (production) methods for crude oil that go beyond the more conventional secondary recovery techniques of pressure maintenance and waterflooding. Analogous to tertiary recovery methods. See Treas. Reg. 1.43-2(e). EOR methods that are widely used include CO_2 miscible flood, steam drive, steam soak, and hydrocarbon miscible flood. EOR methods are not restricted to secondary or even tertiary projects. Some operators initiate an EOR method with the start of production from a reservoir for operational reasons or to maximize ultimate recovery.
Ethanol	A clear, colorless, flammable alcohol. Ethanol is typically produced biologically from biomass feedstocks such as agricultural crops and cellulosic residues from agricultural crops or wood. Ethanol can also be produced chemically from ethylene.
Excess IDC	Intangible drilling cost (IDC) paid or incurred in connection with producing wells, less the amount that would have been allowable for the taxable year had the costs been capitalized and recovered by cost depletion or straight-line 120-month amortization. See IRC section 57(a)(2).
Exchange Oil	Name given to oils exchanged between companies. Company A has excess oil on the West Coast but needs oil on the East Coast. Company B has excess oil on the East Coast but needs oil on the West Coast. Rather than incur large transportation costs, Company A exchanges oil with Company B.
Expendable Wells	Another name for exploratory and delineation wells drilled in relatively deep waters and which the operators have no intention of completing for production.
Expired Lease	A lease that is no longer in force due to either an expiration of a time limit or nonpayment of delay rentals.
Exploration Rights	Permission granted by landowners allowing others to enter upon their property for the purposes of conducting geological or geophysical surveys. Sometimes called shooting rights.
Exploratory Well	A well drilled in a nonproductive area in search of oil or gas deposits. Sometimes it is called a wildcat well.
Farm-in	An arrangement whereby one working interest owner acquires an interest in a lease owned by another. Consideration for the transfer is usually an agreement by the transferee to pay all or part of the drilling and development costs, and the transferor frequently retains some interest.
Farm-out	The same thing as a farm-in, but seen from the opposite perspective. The arrangement is a farm-in to the one who acquires the interest and a farm-out to the one who transfers it.
Federal Energy Regulatory Commission (FERC)	The U.S. Agency that regulates interstate natural gas and oil pipelines.
Fee Interest	The ownership of both surface and mineral rights.
Feedstock	Crude oil or other hydrocarbons that are the basic input to a refinery, petrochemical plant, or intermediate processing units.
Field (oil or gas)	An area consisting of one or more reservoirs that are generally related to the same geological feature or condition.
Field Price	Posted price of oil taken from a specific field.
Flashing	To vaporize from heated charge stock, to distill. Vacuum flashing of straight-run residue allows further distillation without cracking.
Flow Line	Surface pipe through which oil or gas is pumped or flowed from the well to either processing equipment or storage facilities.
Footage Drilling Contract	A well drilling contract that provides for payment at a specified price per foot for drilling to a certain depth.
Foreign Oil and Gas Extraction Income (FOGEI)	Taxable income derived from all sources outside the United States and possessions from the extraction of minerals from oil or gas wells; or, taxable income from the sale or exchange of assets used by the taxpayer in the business of extracting minerals from oil or gas wells.
Foreign Oil Related Income (FORI)	Taxable income derived from sources outside the U.S. and its possessions from the processing of oil and gas into their primary products; the transportation, distribution and sale of oil and gas and their primary products; the disposition of assets used in these activities, excepting the sale of the stock of any corporation; or, the performance of any directly related services.
Forward Contract	A transaction common to many industries, including commodity merchandising, in which the buyer and seller agree upon delivery of a specified quality and quantity of goods at a specified future date for a price agreed upon in advance or to be determined at the time of delivery.
FPSO	Floating production, storage and offloading unit. A vessel used for the processing of oil and gas production and for temporary storage of oil. May be designed to receive hydrocarbons produced from nearby platforms or a subsea template. Oil is usually offloaded onto another tanker, but can be transported through a pipeline. Used frequently outside the U.S. The first operation of an FPSO in the U.S. Gulf of Mexico was in 2012.
Fraction	A portion of distillate (having a particular boiling range) separated from other portions in the fraction distillation of petroleum products.
Free-Well Agreement	A form of sharing arrangement in which one party drills one or more wells completely free of cost to a second party in return for an interest in the property.
Futures Contract	A firm commitment to deliver or receive, at a specified price and grade, a specified quantity of a commodity during a designated month that is traded through an exchange.
Futures Price	The price of a given commodity futures unit determined on a futures exchange, via open outcry or electronic trading.
Gas Payment	A production payment payable out of gas.

Term	Definition
Gasohol	Motor gasoline containing alcohol (generally ethanol but sometimes methanol) at a concentration between 5.7 percent and 10 percent by volume. See also E10.
Gasoline	A volatile liquid fuel that is derived from the distillation of crude oil and is well suited for use in spark-ignited internal combustion engines. Motor gasoline is gasoline that contains additives that allows it to meet certain ASTM requirements.
Geological and Geophysical (G&G) Costs	These costs are expended for the acquisition of information relative to subsurface formations. This information may be the result of interpretative work of geologists; seismic surveys; gravity meter surveys; magnetic surveys; core samples or any other method used in the industry. The costs are capital in nature and recovered via depreciation if incurred in the U.S. See IRC 167(h). Foreign G&G costs are recovered via the methodology of Rev. Rul. 77–188, 1977–1 C.B. 76 and Rev. Rul 83–105, 1983–2 C.B. 51.
Gravity	Short for "Specific gravity". It is a measure of the density of oil relative to water. In the oil industry, gravity is usually expressed in degrees API, which has a scale that is inversely proportional to specific gravity. Light oils have a high API gravity (e.g., 40° API). Heavy oils have a low API gravity (e.g., 20° API). Extra-heavy oils have an API gravity near 10° API, which is the same density as water at 60°F. The API Gravity is calculated from the specific gravity at 60°F using a formula. API Gravity = [(141.5 / Specific Gravity at 60°F) − 131.5]
Gross (vs. Net)	Items that are specific to a company, such as acreage under lease, wells operated, or estimated reserves, may be expressed on a gross or net basis. Gross basis typically implies the entire amount or volume. The net number of acres or wells is usually reflective of a company's working interest. The net amount of estimated reserves or income is usually reflective of a company's revenue interest (working interest less the burden of royalty, over-riding royalty, and net profit interests).
Gross Income from the Property	Since crude oil and natural gas are normally sold directly at or near the wellhead, the gross sales from which the percentage depletion allowance is computed are usually the actual sales prices. When oil or gas is transported from the premises or converted into a refined or manufactured product prior to sale, the representative market or field price (RMFP) is used for purposes of computing percentage depletion. See Treas. Reg. 1.613-3.
Heavy Crude Oil	Crude oil of 20° API gravity or less (adjusted to 60° F). There are perhaps billions of barrels of heavy oil still in place in the U.S. that require special production techniques, notably steam injection or steam soak, to extract them from the underground formations.
Hedge	A transaction entered into primarily to manage price risk by taking a position in a financial product equal and opposite to an existing or anticipated cash position or by shorting a security similar and equal to one in which a long position has been established.
Held By Production	A provision in a mineral lease (or other agreement) that grants the lessor the right to operate the property (or concession) as long as it produces a certain amount of oil or gas (usually each month). Sometimes abbreviated as "HBP."
Henry Hub	A pipeline hub on the Louisiana Gulf coast. It is the delivery point for the natural gas futures contract on the New York Mercantile Exchange (NYMEX).
Horizontal Drilling	The process of boring a vertical hole into the ground, but at a predetermined depth directing the path of the bit so that the hole reaches a horizontal orientation at a depth that coincides with a specific geologic formation. The boring of the horizontal section continues until the desired length of it is achieved.
Hydraulic Fracturing	The process of forcing a fluid, usually water laden with a "proppant" such as sand into a gas or oil bearing formation that has very low native permeability. The injection pressure is raised until such point that the formation "breaks down" or "fractures" , which allows the fluid to carry the proppant into the small cracks and fissures that are created. the proppant is designed to keep them from completely closing shut when the injection ceases and the pressure is released. During the "flow back" or "clean-up" period most of the injected fluid and some proppant is recovered. The result of the process is to allow oil and gas to much more readily flow through the formation and into the well.
Hydrocarbon	Any of the compounds made up exclusively of hydrogen and carbon in various ratios.
Hydrocracking	Catalytic cracking in the presence of hydrogen. The combination of the hydrogen, the catalyst, and the operating conditions (temperature and pressure) permit cracking low quality gas oils that would otherwise be made into distillate fuel. The heavy hydrocrackate product contains aromatics.
Hydro-desulfurization (HDS) Unit	A unit within a refinery that uses hydrogen in a catalytic process to remove sulfur from natural gas and from refined petroleum products such as gasoline, jet fuel, kerosene, diesel fuel, and fuel oils. Many refineries constructed or expanded their HDS unit in order to produce ULSD when it was mandated by the EPA.
Hydroforming	A special catalytic hydrogen reforming process employed for upgrading straight run gasolines.
Independent Producers and Royalty Owners Exemption	An exemption from the denial of percentage depletion provided in IRC 613A(a). This exemption is provided in IRC 613A(c) and allows percentage depletion to be computed on up to 1,000 BOE per day of the taxpayer's production. Independent Producers are defined in IRC 613A(d) as producers who do not have more than $5,000,000 in retail sales of oil or gas in a year and who do not refine more than an average of 75,000 barrels of crude oil per day during the year.
Injection or Input Well	A well used to inject gas, water, LPG'S, or other foreign substances under pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.
In Situ	In terms of oil and gas production, "within the reservoir" . for example, using the *in situ* combustion process to heat fluids and create pressure in the reservoir in order to recover additional quantities of oil.
Intangible Drilling and Development Costs	Those expenditures which do not have a salvage value and which are incurred in the drilling and deepening of an oil and gas well.
Integrated Oil Company	A company engaged in all phases of the oil business, i.e., production, transportation, refining, and marketing. It frequently also includes petrochemicals/chemicals.
IPAA	Independent Petroleum Association of America.
Isomerization	Process for altering the fundamental arrangement of the atoms in a molecule without adding or removing anything from the original materials. In petroleum refining, straight-chain hydrocarbons are converted to branched-chain hydrocarbons of substantially higher octane rating, in the presence of a catalyst, usually at moderate temperatures and pressures.
Jack-up Rig	A mobile drilling platform with extendible legs for support on the ocean floor.
Jobber	A buyer of oil products from refiners for resale to retail outlets.
Joint Operating Agreement	(1) An agreement between two owners or among several concurrent owners for the operation of a leasehold for oil, gas, or other minerals. The agreement calls for the development of the lease or the premises by one of the parties to the agreement, who is designated as operator or unit operator for the joint account. All parties share in the expenses of the operations and in the proceeds resulting from the development. (2) An agreement among adjoining landowners or leaseholders to develop a common pool, again sharing expenses and profits.
Joule	A unit of energy. One joule is equivalent to 9.48 × 10 to the power of negative 4 to BTUs (.000948 BTU).
Landman	A person engaged in securing oil and gas leases from landowners.
Lease Agreement	The legal instrument by which a leasehold is created in minerals. A contract that, for a stipulated sum, conveys to an operator the right to drill for oil and gas. The mineral lease is not to be confused with the usual lease of land or a building.
Lease and Well Equipment	Capital investment in items having a potential salvage value. Such items include the cost of casing, surface pipe, tubing, wellhead assemblies, pumping units, lease tanks, treaters, and separators.
Lease Bonus	Consideration paid by the lessee to the lessor for executing the lease.
Leasehold Costs	Costs of acquiring and holding a lease, such as the lease bonus, commissions paid to landmen, cost of title work, and capitalized delay rental payments.
Lifting costs	Costs of operating wells for the production of oil and gas (producing costs).
Light Ends	In any given batch of oil, that portion of lowest boiling point. In gasoline, it is the portion distilling off up to 158° F. In making lubricating oils, the light ends must be removed in order to produce finished oils of high flash point.
Limited Partnership	A form of organization, frequently employed in financing oil and gas ventures, by which an investor of funds becomes a limited partner with limited liability and limited management rights.
Line Fill	The volume of product required in a liquids pipeline at all times to allow for normal operations. IRS examiners may also use the term to describe the volume of partially processed product within a refinery.
Line Pack Gas	The volume of gas maintained in a pipeline to maintain minimum operating pressure.
LNG	Liquified Natural Gas, composed almost entirely of methane. The temperature at which methane becomes liquid at normal pressure is -260° F. In liquid form, natural gas retains only $^{1}/_{600}$ of its original volume.
Low sulfur diesel (LSD) fuel	Diesel fuel containing more than 15 but less than 500 parts per million (ppm) sulfur.
Marginal Production	Domestic crude oil or natural gas that is produced from a stripper well property for the calendar year in which the taxable year begins, or oil produced from a property whose production is substantially all heavy oil during such calendar year. See IRC 613A(c)(6)(D), IRC 613A(c)(6)(E) and IRC 613A(c)(6)(F) .
Marginal Wells	A well of such low producing capacity that the profitability of future production is marginal. A specific definition is contained in IRC 45I(c)(3) for the Marginal Well Tax Credit.
Mark to Market	This is a procedure in which the broker debits or credits the available balances of customers' accounts daily for changes in the value of open contracts.

Term	Definition
MCF	Thousand cubic feet.
Mercaptans	Organic compounds having the general formula R-SH, meaning that the thiol group (SH) is attached to a radical, such as CH3 or C2H5. The simpler mercaptans have a strong, repulsive, garlic like odor which becomes less pronounced with increasing molecular weight and higher boiling points.
Methane	Methane (CH4) is a simple gaseous hydrocarbon associated with petroleum. Natural gas used by residential and industrial customers is nearly 100 percent methane.
Mineral Deed	A lease instrument that conveys an interest in minerals on or under a tract of land.
Mineral Interests (Mineral Rights)	The ownership of the minerals and the right to remove them from the property.
Minimum Royalty	An obligation of a lessee to periodically pay the lessor a fixed sum of money after production occurs, regardless of the amount of production. Such minimum royalty may or may not be chargeable against the royalty ownership of future production.
MMBTU	Million British Thermal Units.
MMCF	Million cubic feet.
MODU	Mobile Offshore Drilling Unit. Includes "jack-ups" , "semi-submersibles" , and "drill ships" . Somewhat analogous to barges that hold a drilling rig, but much more sophisticated and versatile.
MOGAS	Motor gasoline.
Mud Pit	Tank near the drilling rig used for storage of drilling mud during drilling operations. The drilling mud is prepared for drilling in the pit by mixing the mud and water. Slush pumps withdraw the mud from the pit and circulate it down the drill pipe. At the surface the mud passes back to the mud pit through the "shale shaker" which removes the drill cuttings that were carried to the surface by the mud.
Multiple Completion Well	An oil and/or gas well completed in such a manner that it is capable of producing oil and/or gas separately from two or more reservoirs. Such separate production may be simultaneously through two or more strings of tubing or through a string of tubing and between the tubing and the casing.
Natural Gas	Any hydrocarbon product (other than crude oil) of an oil or gas well if a deduction for depletion is allowable under IRC 611 with respect to such product. Specifically natural gas refers to any hydrocarbon gas.
Natural Gas Liquids	Natural gas liquids are the heavier hydrocarbon liquids produced along with natural gas, including butane, propane, natural gasoline and ethane.
Natural Gas Sold Under a Fixed Contract	Domestic natural gas sold under a contract in effect on February 1, 1975, under which the price cannot be adjusted to reflect the increase in income tax due to the repeal of percentage depletion. See IRC 613A(b)(3)(A).
Natural Resource Recapture Property	For purposes of IRC 1254, a mineral interest property which had depletion deductions or IDC incurred with respect to it.
Net Profits Interest	An interest in production created from the working interest and measured by a certain percentage of the net profits from the operations of the property.
Neutral Oils	Term used quite generally to mean a lubricating oil of medium viscosity made from a wax bearing crude.
Non-consent	Term used to describe a member of a joint venture that declines to participate in an investment of the joint venture, such as drilling a particular well or completing a well after it reaches total depth. The joint venture agreement may allow the non-consenting member to regain its working interest in the well after the other members recoup their costs and a risk-reward (e.g., costs times 200 percent).
Nonconventional Source Fuels Credit	A tax credit authorized by IRC 45K for sales of qualified fuels (defined in IRC 45K(c)) to unrelated persons.
Nonoperating Interest	An economic interest that does not meet the definition of operating interest as defined in Treas. Reg. section 1.614–2(b). A royalty, overriding royalty, or net profits interest is a nonoperating interest. A production payment has the attributes of a nonoperating interest, except that it is not a continuing interest. It may or may not be treated as an economic interest treatment. See IRC 636 and the regulations thereunder.
Nonproductive well	The term used in the IRC 57(a)(2)(B) and 263(i) and Treas. Regs. 1.263A-13, 1.612-4, 1.612-5 and 1.1254-1 to describe a dry hole. See Dry Hole.
Normal	When used to refer to a chemical compound, this means the straight-chain version. Branched-chain molecules have higher octane numbers.
NYMEX	New York Mercantile Exchange. A commodities futures exchange that lists several types of crude oil, natural gas, heating oil, gasoline, and ethanol.
OCS	Outer Continental Shelf. In general, the offshore areas that are the domain of the U.S. government. Treas. Reg. 301.9001-2 contains the formal definition: "Outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in Section 1301 of Title 43 and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.
Octane Number, Motor Method (MON)	Octane number of automotive gasolines determined by a method of test that indicates the knock characteristics under severe conditions (high temperatures and speed).
Offset Well	Well drilled on one tract of land to prevent drainage of oil or gas to a nearby tract on which another well has been drilled.
Oil or Gas Property	Each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land.
Oil Payment	A production payment payable from oil.
Oil Sands	A term commonly used in Canada to describe heavy and extra heavy deposits of petroleum. Shallow deposits are recovered by mining. Deeper deposits are recovered by in situ methods. The term "tar sands" is more commonly used in the U.S.
Oil Shale	A sedimentary rock containing kerogen, a solid organic material. Liquid hydrocarbon can be obtained by retorting. See Rev. Rul. 92-100; 1992-2 C.B. 7 for the distinction between oil shale and liquid hydrocarbons (oil) that sometimes exists naturally in a shale formation.
Operating Mineral Interest	A separate mineral interest in respect of which the costs of production of the mineral are required to be taken into account by the taxpayer for purposes of computing the 50 percent of taxable income from the property in determining the deduction for percentage depletion. See Treas. Reg. 1.614–2(b). The usual working or operating interest consists of $^{7}/_{8}$ of the production subject to all of the costs of drilling, completing and operating the lease. See *L.W. Brooks Jr. v. Commissioner*, 424 F.2d 115 (5th Cir. 1970) and Treas. Reg. 1.614-2(b).
Operator	The individual or company responsible for conducting exploration and production activities in a defined area. In a joint venture the operator is usually the holder of the largest operating mineral interest.
Overriding Royalty	A right to a stated fraction of production, in kind or in value, created from the working interest, having a term coextensive with that of the working interest, but not burdened with development or operation costs.
Oxidation	In general, the process in which oxygen reacts with a compound. The oxidation reaction in petroleum may lead to degrading gum or resin formation which is common in gasolines and jet fuels, particularly those that contain considerable unsaturated compounds.
Paraffinic	Refers to a petroleum product containing large amounts of alkyl compound of the formula CnH2n+2. Alkyl compounds are saturated organic molecules with important lubricating properties found in the heavier members of the series.
Participating Area	That part of a unit area which is considered reasonably proven to be productive.
Participation Agreement	An agreement between two or more parties to share in the cost and production of a well.
Passive Activity	Income/losses generated from an activity (trade or business) in which the taxpayer does not materially participate or from a rental activity, usually regardless of participation levels.
Pay	The reservoirs or portion of reservoirs penetrated by a well that are expected to produce oil and gas in commercial quantities are called "pay sands" . Gross pay is the total thickness (usually measured vertically) of a pay interval. Net pay is gross pay less those portions that are not expected to produce hydrocarbons due to factors such as poor permeability.
Payout	Recovery from the net proceeds of production of the entire cost of drilling, completing, and equipping a well.
Percentage Depletion	The method of computing the depletion deduction based upon an arbitrary percentage of gross income from production (gross income from the property). The percentage depletion allowance is limited to 100 percent of the taxable income from oil and gas operations computed with respect to each separate operating mineral interest. Percentage depletion allows a taxpayer to deduct costs in excess of basis. See Treas. Reg. 1.613–1(a).
Perforating	The piercing of the casing wall and cement to provide holes through which the hydrocarbons may enter the well bore.
Permeability	A measure of the resistance provided by the reservoir rock to the flow of fluids through it. Reservoir rock that allows fluids to easily flow through it has high permeability.
Petrochemicals	Chemicals derived from petroleum feedstocks for the manufacture of a variety of plastics, synthetic rubber, etc.
Petroleum	Sometimes viewed as analogous to (liquid) crude oil. A more precise definition by the Society of Petroleum engineers is "[N]aturally-occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulfur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulfide" . The non-hydrocarbons are considered impurities. See *Sour Oil or Gas*.

Term	Definition
Petroleum Coke	A solid residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking. Produced at a refinery in the coker unit.
Platform	A structure that supports assets such as wells, production equipment, a drilling rig, personnel accommodations, or combinations of those assets. Designed to stay at one site for many years. Platforms can either rest on the seabed or be of a floating design that is kept on location by positioning cables.
Pool of Capital	Under this doctrine, a taxpayer contributing property, cash or drilling services to the drilling of an oil or gas well in return for an economic interest in that well makes a capital contribution to the "pool of capital" available to the venture. The taxpayer is considered to have received a capital interest in the well that was not taxable upon its receipt. See Rev. Rul. 77–176, 1977–1 C.B. 77.
Pooling	The bringing together of small tracts sufficient for the granting of a well permit under applicable spacing rules, as distinguished from unitization which is the joint operation of a reservoir. Pooling is important to prevent the drilling of unnecessary and uneconomic wells. See Treas. Reg. 1.614–8(b)(6).
Porosity	A measure of the amount of void space (pores) in a unit of reservoir rock. Expressed as a percent. For example, a sample of rock that has a bulk size of 1.0 cubic feet and 15 percent porosity could hold 0.15 cubic feet of fluid.
Possible Reserves	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. Possible Reserves are generally not consistent with minerals described in Treas. Reg. 1.611-2(c)(1).
Post Production Costs	Costs incurred by the operator between the point of production and the point of sale, such as for dehydration, compression, transportation and storage. Disputes can arise when the operator charges the royalty owner for a share of these costs. State law varies as to what costs can be charged to a royalty owner.
Pour Point	The lowest temperature at which an oil will pour or flow when chilled without disturbance under specified conditions. By American Society for Testing and Materials (ASTM) instruction, it is taken as the temperature 5° F above the solid point.
Primary Production	Oil production which is recovered through the use of the natural energy source in the reservoir. Also called primary recovery.
Primary Term	The period of time a lease may be kept in force even though no drilling operations have commenced. Payments of delay rentals may or may not be required. The time period varies.
Probable Reserves	An incremental category of estimated recoverable volumes. Probable Reserves are those additional reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. Probable Reserves are generally consistent with minerals described in Treas. Reg. 1.611 -2(c)(1)(ii). They are reasonably analogous to "probable and prospective" ores or minerals.
Producer	One who owns an economic interest in a well that produces oil or gas.
Production Payment	A share of the minerals produced from a lease, free of the cost of production, that, *inter alia*, terminates when a specified sum of money has been realized. Production payments may be reserved by a lessor or carved out by the owner of the working interest. See Treas. Reg. 1.636–3(a)(1)&(2).
Production Taxes	Taxes levied by state governments on mineral production based on the value and/or quantity of production. These are also referred to as severance taxes.
Project Area	In the search for mineral producing properties, it is customary for a taxpayer to conduct geological and geophysical studies and surveys within a large geographical area (the project area). The purpose of these initial reconnaissance type surveys is to identify specific geological features with sufficient mineral producing potential to merit further exploration. The costs incurred with respect to these initial surveys are capital in nature. See Geological and Geophysical Costs for discussion of cost recovery.
Propane	Propane (C_3H_8) is a gaseous hydrocarbon associated with petroleum. Commonly used for heating and cooking when natural gas (methane) is not available. When compressed to a moderate pressure it becomes a liquid, which facilitates transportation and storage.
Property	Each separate interest owned by a taxpayer in each mineral deposit in each separate tract or parcel of land. See Treas. Reg. 1.614–8.
Proved Reserves	An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. Proved reserves correspond to the recoverable units described in Treas. Reg. 1.611-2(c)(1).
PSC	Production Sharing Contract. Commonly used outside the U.S. to explain the rights and obligations of the host government, national oil company, and other oil companies in regards to a specific area. Somewhat analogous to a combination of a lease and a joint operating agreement.
Pumping unit	The most common version is the pump jack used on onshore wells. Offshore oil wells use a "gas lift" system whereby gas is continuously injected into the tubing at specific depths to lessen the hydrostatic head of the produced fluids. Wells that need to produce a very high rate of fluids, such as wells with extremely high water-oil ratio, use an electrically powered submersible pump. Subsea flowlines which carry both oil and gas are sometimes boosted by "multiphase pumps" .
Recompletion	The operation to change the productive interval of a well. Involves sealing off the previous interval with cement or a mechanical plug and perforating the new interval. May involve the installation of a new string of tubing or resetting the existing string. Recompletions are usually done "uphole" to access "behind the pipe" reserves in shallower reservoirs that have not yet been produced by the well.
Reconnaissance Survey	A survey of a project area utilizing various geological and geophysical exploration techniques to identity specific geological features with sufficient mineral producing potential to merit further exploration. See Geological and Geophysical Costs for discussion of cost recovery.
Recoverable Reserves	The total recoverable units (e.g., barrels or thousands of cubic feet) of ores or minerals reasonably known to exist in place as of the estimation date. The estimation of recoverable reserves must be made in accordance with the method current in the industry in light of the most accurate and reliable information obtainable. The estimation must be made in the first taxable year within which depletion is taken with respect to a mineral interest and the recoverable reserves can only be reestimated if it is determined by operations or development work that the number of recoverable reserves are materially greater or less than the number remaining from the prior estimate. See Rev. Rul. 67–157, 1967–1 C.B. 154, G.C.M. 33140 (Nov. 24, 1965). Rev. Proc. 2004-19, 2004-1 C.B. 563, provides an elective safe harbor that taxpayers may use to determine recoverable reserves of its properties.
Reduced Crude	The bottoms from a distillation of crude oil.
Reformate	Liquid product from the reforming process (increased percentages of aromatics and iso-paraffins) and feedstock for gasoline blending and/or further processing into petrochemicals.
Reforming	A catalytic process for converting low octane number naphthas or gasolines into high octane number products.
Regeneration	In catalytic cracking, removal of carbon from the catalyst in order to make it suitable for reuse.
Reservoir	A porous, permeable sedimentary rock containing commercial quantities of oil or gas.
Residual (Residue or Residuum)	The dark colored, highly viscous oil remaining from oil after the more volatile portion of the charge has been distilled.
Residue Gas	Natural gas, mostly methane, which remains after processing in a separator or plant to remove liquid hydrocarbons contained in the gas when produced.
Retained Interest	A special nonoperating interest retained by the lessor when the lessor transfers the responsibilities for developing the property to another party.
Retorting	Generally refers to heating a substance, such as oil shale, to a very high temperature in the absence of oxygen so that destructive distillation occurs.
Reversionary Interest	In a carried interest arrangement, the particular working interest percentage that the carried party regains after the carrying party recoups the costs it incurred as allowed by the agreement between the parties.
RMFP	Representative Market or Field Price. A weighted average price of oil or gas that takes into account all wellhead sales of gas, which is comparable to the gas of the producer-manufacturer in terms of quality, pressure, and location. See Gross Income from the Property and *IRM 4.41.1.3.9.1.3*.
ROV	Remotely Operated Vehicle. A type of small unmanned submarine that is used in deepwater drilling and construction activities.
Royalty	A share of the gross production of the minerals (or a share of the proceeds from the sale thereof) on a property by the landowner without bearing any of the cost of producing the minerals. The usual landowner's royalty is one-eighth of gross production. See Treas. Regs. 1.614–2(b) and 1.614–5(g).
Run Statement	A statement supplied by the purchaser of oil or gas to an interest owner setting forth the gross volume of product taken, sales value, taxes paid, and net payment to the owner. The run statement usually accompanies the payment for the runs.
Run Ticket	Evidence of receipt or delivery of oil issued by a pipeline or other carrier or purchaser.
Runs-to-Stills	The amount of crude oil withdrawn from inventory and placed into production by a refiner.
SAE Viscosity	A system for classifying motor oils according to their viscosities established by the Society of Automotive Engineers.
Salt Water Disposal Wells	Wells used for disposal of saltwater that is produced along with oil or gas.
Secondary Production	Oil recovered by a secondary recovery method used to recover oil from a field by a means other than the normal pumping or flowing methods. This will normally involve the flooding of the formations through injection wells with water to drive the recoverable oil to producing wells.
Seismic Survey	Geophysical information on subsurface rock formations gathered by means of a seismograph.

Term	Definition
Separator	A gas-oil separator is a cylindrical tank, usually located at or near the tank battery, which is used to separate oil and/or gas well effluent into liquids and gas at or near atmospheric pressure.
Severance Taxes	See Production Taxes.
Shale	A fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. Shale is normally impenetrable to fluid flow, and often forms the cap or seal that traps petroleum in underlying reservoirs. Some shales act as both the source and the reservoir of oil and gas. Advances in hydraulic fracturing and horizontal drilling have made it possible to economically produce oil or gas from certain shale formations.
Shale Gas	Natural gas produced from a shale formation, often as a result of hydraulic fracturing and horizontal drilling.
Shale Oil	Oil that naturally exists within a shale formation. Large amounts have been produced from wells in recent years due to hydraulic fracturing and horizontal drilling. See also Rev. Rul. 92-100, 1992-2 C.B. 7.
Sharing Arrangement	A transaction where a person contributes to the acquisition, exploration, or development of an oil or gas property and receives as consideration an interest in the property to which the contribution is made.
Shooting Rights	See Exploration Rights.
Short	A trader obtains a short position by selling a security he does not own and making delivery with borrowed securities.
Shut-in Wells	A producing well that has been closed down temporarily, or one that was never connected to a pipeline because of its very remote location.
Side Tracking	An operation involving the use of an existing well to drill a second hole.
Sour Oil or Gas	Oil or gas containing more than a certain proportion of hydrogen sulfide or other sulfur compounds, usually 0.5 percent or more.
SPE	Society of Petroleum Engineers.
Speculator	An individual, or entity, that is not a hedger. One who trades for profits by anticipation of price movements.
Spot price	The price at which a physical commodity is selling at a given time and place, often involving prompt delivery. Same as cash price. The spot price differs from a contract or term price in that the latter involves multiple sales over time, whereas the former usually involves a single cargo or transaction.
Spread (or Straddle)	The purchase of one futures delivery and the sale of another futures delivery month of the same or similar commodity, or the purchase of a commodity in one market against the sale of that commodity or a like commodity in another market to take advantage of differences or anticipated differences in price relationships.
Spud	To start the actual drilling of a well.
Straight Run	In the context of refining crude oil, the gasoline that is obtained by distillation with no additional processing.
Stripper Oil	Oil recovered from a stripper well. See IRC 613A(c)(6)(E).
Stripper Well Property	A property where the average daily production of domestic crude oil and gas produced from the wells on the property during a calendar year divided by the number of such wells is 15 barrel equivalents or less. See IRC 613A(c)(6)(E).
Subsea Production System	Similar to the assets needed to carry production from onshore wells to processing equipment, but located on the seabed instead. Subsea christmas trees are called marine trees or "wet trees" . A "jumper" carries production from an individual well to a subsea manifold. A subsea flowline then carries the production towards a platform for processing. The flowline transitions to a vertical "riser" as it approaches the platform. "Umbilical" lines run from a control center on the platform to each well and manifold in order to provide power, control, data communications, and chemicals.
Sweet Oil or Gas	Crude oil or natural gas which contains little or no sulphur or hydrogen sulfide.
Take or Pay Contract	A contract by which a pipeline company, within a specific period of time, must pay for an agreed number of units whether or not the units have been taken. The pipeline company usually has the right to take these units, within a specified time period, without further payment.
Tank Battery	Two or more tanks connected together on a property to store oil production prior to sale and/or removal.
Tank Farm	A number of oil storage tanks located together where oil gathered by a pipeline company is stored prior to transportation to the refinery.
Tar Sands	Native asphalt, solid and semisolid bitumen, including oil-impregnated rock or sands from which oil is recoverable only by special treatment. Processes have been developed for extracting the oil, referred to as synthetic oil. See TAM 8940004 (June 20,1989) and FEA Ruling 1976–4, 41 FED. Reg. 25, 886 (1976).
Term Price	A contract price, usually involving multiple deliveries over time. See Spot Price.
Tertiary Production	A method used to recover oil after a secondary method has been applied, typically by injecting steam, solvents, or chemicals to modify the properties of the oil in the formation so that it will more readily flow towards production wells.
Tight Gas	Natural gas produced from a "tight" formation (usually a sandstone) that requires hydraulic fracturing in order to produce in substantial quantities because of extremely low native permeability. Incentives formerly available under IRC 45K led to substantial domestic production of gas from tight formations.
Top Lease	The granting of a new oil or gas lease prior to the termination of an existing lease; the new lease becoming effective upon expiration of the old lease.
Topped Crude	Crude oil from which some of the lighter constituents have been removed by distillation.
Tubing	The pipe that is placed into the casing of a well and through which produced fluids flow to reach the wellhead. Common diameters are 2.5 inch to 4.5 inch.
Turnaround	The planned periodic inspection and overhaul of the units of a refinery or processing plant requiring the shutting down of a refinery (or individual units) for inspection, cleaning, repair, or upgrading.
Turnkey Well	A completed well, drilled and equipped by a contractor for a fixed price.
Ullage	The distance from a given point at the top of a container down to the surface of the liquid.
Ultra-low sulfur diesel (ULSD) fuel	Diesel fuel containing a maximum 15 parts per million (ppm) sulfur.
Unit of Production Method	A method for computing depreciation or amortization based on a ratable recovery of basis over the expected number of units to be produced by an asset. The method is similar to the computation of cost depletion.
Unitization	A term denoting the joint operation of separately owned producing leases in a pool or reservoir. Unitization makes it economically feasible to undertake cycling, pressure maintenance, or secondary and tertiary recovery programs. See Treas. Reg. 1.614–8(b)(6).
Unrealized Profit or Loss	The profit or loss on open positions that has not become actual. It is realized when the security or commodity futures contract in which there is a gain or loss is actually sold.
Viscosity	That property of a liquid which causes it to offer resistance to flow. The higher the viscosity of an oil the less readily it will flow; the lower the viscosity of the oil the more readily it will flow. Motor oil with a viscosity of SAE 10 will flow more readily than a SAE 20.
Volatility	A measure of the propensity of a substance to change from the liquid or solid state to the gaseous state. A volatile liquid is one which readily vaporizes at comparatively low temperatures.
Volumetric Production Payment	A production payment that is to be satisfied by delivery of a certain volume of hydrocarbons as distinguished from one to be satisfied by delivery of hydrocarbons of a specific value.
Wash Sale	A fictitious transaction to make it appear that there was a trade. This is prohibited by the Commodity Exchange Act. See wash trading.
Wash Trading	Entering into, or purporting to enter into, transactions that give the appearance of purchases and sales but usually do not result in a change in the traders' market position.
Waterflooding	A method of secondary recovery, in which water is injected into an oil reservoir for the purpose of pushing the oil out of the reservoir rock and into the bore of a producing well.
Well Bore	The hole that is created by the process of drilling.
Wellhead	Equipment used to maintain surface control of a well. See Christmas Tree.
Wildcat Well	A well drilled in an unproved area, far from a producing well; an exploratory well in the truest sense.
Working Interest	See *Operating Mineral Interest*.
Workover Costs	Similar to Recompletion Costs, but usually to establish or re-establish production from the same reservoir from which the well has produced. Typical activities include cleaning, re-acidizing, re-perforating, re-cementing, replacing corroded tubing, and similar costs. They may be recurring type costs but usually not on an annual or shorter time basis.
WTI	West Texas Intermediate. A crude stream produced in Texas and southern Oklahoma which serves as a reference or "marker" for pricing a number of other crude streams and which is traded in the domestic spot market at Cushing, Oklahoma. WTI is considered a light, sweet crude.
Yield	In petroleum refining, the percentage of product or intermediate fractions based on the amount charged to the processing operation.

Exhibit 4.41.1-45
Definitions Related to Oil and Gas Reserves in SEC Regulation S-X Prior to 2010

Certain definitions related to oil and gas reserves are contained in Regulation S-X (17 CF § 210.4-10) for filings with the Securities and Exchange Commission (SEC) prior to 2010.

Proved oil and gas reserves. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

1. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
2. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
3. Estimates of proved reserves do not include the following: a) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves" ; b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved developed oil and gas reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage is limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Exhibit 4.41.1-46
Definitions Related to Oil and Gas Reserves in SEC Regulation S-X After 2009

Certain definitions related to oil and gas reserves are contained in Regulation S-X (17 CF § 210.4-10) for filings with the Securities and Exchange Commission (SEC) after 2009.

Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes:

1. The area identified by drilling and limited by fluid contacts, if any, and
2. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

1. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
2. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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